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Cost Analysis of Controlling Carbon Dioxide Flue Gas Emissions from Canadian Power Utilities

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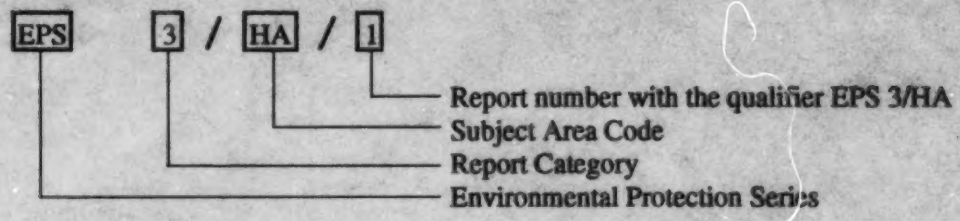

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Abstract

This report was jointly written by Radian Corporation (Part 1) and Monserco Ltd. (Part 2). In Part 1, currently available technologies for removing and disposing of carbon dioxide (CO_2) from fossil fuel power plants are evaluated, including their feasibility, stage of development, effect on the environment, and applicability in Canada. In Part 2, the most feasible technologies have been incorporated into a utility computer simulation model (CANSIM). It has been assumed for the simulation that the CO_2 is removed by a solvent, compressed, and disposed of either by injection to deep ocean or by precipitation of carbonates from brine aquifers. If the current level of emissions is maintained, utilities powered primarily by fossil fuel will face an approximately 50% increase in power costs. This would double the capital cost of new fossil fuel plants and reduce efficiency by 25%.

This report was commissioned by Environment Canada to provide a general review of technologies that could be used to remove CO_2 from power plant exhaust gases and to provide an order of magnitude estimate of using CO_2 removal and disposal techniques at Canadian fossil fuel burning power plants. The study is not intended to provide a definitive evaluation of any one option or approach and does not consider in detail potential CO_2 uses, such as in enhanced oil recovery, or CO_2 disposal methods, such as in depleted natural gas reservoirs - options that may be available in parts of Western Canada.

Résumé

Le présent rapport a été rédigé conjointement par Radian Corporation et Monserco Ltd. Dans la première partie, préparée par Radian Corporation, on y examine l'état actuel des techniques en vue de piéger et d'éliminer le CO_2 des centrales alimentées par des combustibles fossiles. On se penche également sur la faisabilité, l'étape de développement, les répercussions environnementales et l'applicabilité à la situation canadienne. La seconde partie, préparée par Monserco Ltd., fait état des techniques les plus praticables introduites dans un modèle informatisé de simulation (CANSIM) des services d'électricité. La simulation suppose que le CO_2 est extrait par un solvant, comprimé et éliminé soit par l'injection en eau profonde, soit par la précipitation des carbonates par des saumures d'aquifères. Si on maintient les émissions à leur niveau actuel, les services d'électricité alimentés principalement par des combustibles fossiles verront leurs coûts d'électricité augmenter d'environ 50 %. De plus, les coûts en immobilisations des nouvelles centrales alimentées par des combustibles fossiles doubleraient et leur rendement serait réduit de 25 %.

Ce rapport a été commandé par Environnement Canada dans le cadre d'une étude générale des techniques qui peuvent servir à éliminer le CO_2 des émissions gazeuses des centrales électriques, afin d'évaluer dans leurs grandes lignes des caractéristiques des techniques de piégeage et d'élimination du CO_2 qui peuvent être utilisées dans les centrales électriques canadiennes alimentées par des combustibles fossiles. Cette étude n'est pas destinée à fournir une évaluation définitive de l'une ou l'autre des options ou approches et n'évalue pas de façon détaillée les utilisations possibles du CO_2, comme la récupération améliorée du pétrole, ou les méthodes d'élimination du CO_2, comme l'injection dans les réservoirs de gaz naturel épuisés, qui pourraient être disponibles dans l'Ouest du Canada.

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Summary

This report reviews currently available technologies for controlling (removing and disposing of) CO_2 emissions that could be used to reduce such emissions from fossil fuel power plants in Canada.

The CO_2 removal systems that were evaluated are summarized in Table 1. The costs of solvent absorption, direct oxygen firing, and cryogenic distillation are based primarily on the cost of the very large compressors required for the process. As compressors of this size are rarely built, the cost estimates of the removal processes are approximate. The solvent absorption option was selected for evaluating the impact on the costs of generating electric power. Due to the inexact nature of the cost estimates, however, the overall results would not change significantly if another technology had been selected.

Table 1 Summary of Carbon Dioxide Removal Systems

Process	Status	Efficiency	Approximate Daily Cost ($/ton)*
Solvent Absorption	In use	90%	$22 000
Direct Oxygen Firing with CO_2 recycle	Pilot Plant	100%	$20 000
Brine Absorption	Theoretical	90%	unknown
Condensation/ Cryogenic distillation	In use	80%	In excess of $25 000
Solid Adsorption	Theoretical	unknown	unknown

* 1 ton = 0.907 tonne

The CO_2 disposal systems that were evaluated are summarized in Table 2. Enhanced oil recovery (EOR) is the only disposal process now in use. It can dispose of only a fraction of the total CO_2 emissions from utilities in Alberta and Saskatchewan. All other disposal methods raise significant environmental concerns. Deep ocean injection is the only disposal method that would appear to have the required capacity. This would require the building of pipelines to pump the gas in dense phase to a point beyond the continental shelf (approximately 400 km offshore). The political and financial implications of doing this would be great.

Table 2 Summary of Carbon Dioxide Disposal Systems

Disposal Technology	Status	Major Environmental Concern
Deep ocean injection	Theoretical	Large quantities of concentrated CO_2 in the deep ocean environment
Brine Absorption and precipitation	Theoretical	Disposal of precipitate waste and land use for precipitation ponds
Enhanced oil recovery/Injection to ground cavities	In use	Maintaining CO_2 in the ground over long periods
Algae ponds	Bench scale	Extensive land area required for ponds

The currently projected CO_2 emissions from Canadian utilities were estimated using the CANSIM utility simulation code with the most recent information on load growth and planned development supplied by the utilities. From this "business as usual" case, controls were applied to those provinces with significant fossil generation so that by the year 2004, total CO_2 emissions would be reduced by approximately 25% from current levels. The potential effect of these controls on emissions is summarized in Figure 1.

Increases in power costs that would result from using these emission control methods are shown in Table 3 for the whole country and by province. The actual emission reductions vary because the CO_2 emission control strategy projected for each province reflects the utilities' proposed expansion plans. The reductions noted in the table are based on the projected uncontrolled values in that year, not the current levels. The increases in power costs are also based on projected costs, without controls in place.

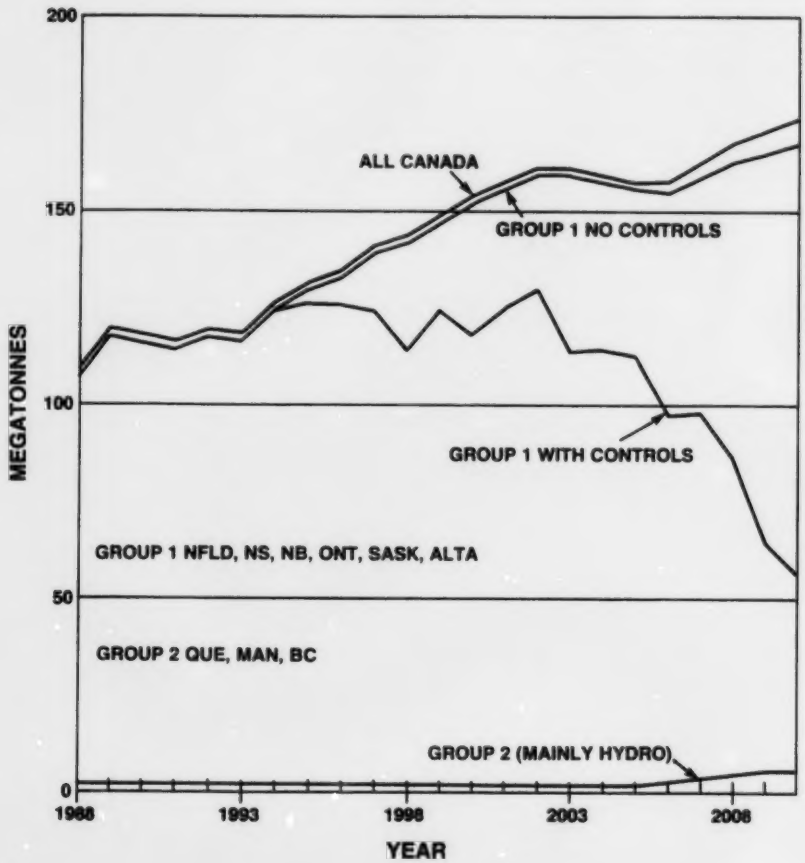

Figure 1 Projections of Carbon Dioxide Emissions from Canadian Electric Power Utilities

Table 3 Carbon Dioxide Reductions and Power Cost Increases by Province

	By 2004		By 2010	
	Reduction in CO_2 Emissions (%)	Increase in Power Cost (%)	Reduction in CO_2 Emissions (%)	Increase in Power Cost (%)
All of Canada	31	14	61	25
Newfoundland	84	27	86	41
Nova Scotia	30	24	52	34
New Brunswick	30	26	75	55
Ontario	28	5	73	10
Saskatchewan	14	23	48	50
Alberta	37	26	67	65

Approximately 110 million tonnes of CO_2 are emitted from electrical utilities in Canada each year. Without controls, this is expected to increase to about 160 million tonnes by the year 2004. It is estimated that controls suggested in this report will reduce emissions to approximately 100 million tonnes in the year 2004, which is a 10% reduction from current levels, and to 60 million tonnes in the year 2010, which is a 50% reduction. The aim was to achieve a 25% reduction in 2004 but this is not expected to be achieved until 2006. The more rapid reduction did not fit current building plans for the utilities and would have required too much retrofitting of removal systems.

Although the increase in power cost may not appear very large, the total annual cost of power in Canada would increase by about 8 billion dollars in 1994 and 20 billion dollars in the year 2010.

PART 1

Section 1

Introduction

Part 1 outlines the results of a study conducted by Radian Corporation for Environment Canada to survey potential technologies for removing and disposing of carbon dioxide from flue gas from Canadian power utilities fired by fossil fuel. Carbon dioxide scrubber technologies or processes are identified and reviewed to evaluate their technical and economic feasibility for such utilities. The complete terms of reference are given in Appendix B. The technologies identified were evaluated with regard to information quality, cost effectiveness, and applicability to Canadian electric power systems. A concise technical description is provided for each technology as well as its operating parameters, capital and operating costs in 1989 Canadian dollars, power requirements in megawatts, and significant environmental considerations.

1.1 Background

The 1988 Conference on the Changing Atmosphere, held in Toronto, focused attention on the "greenhouse effect". The greenhouse effect is produced by a number of gases, with CO_2 being the major contributor. If the predictions concerning global warming are correct, potential solutions for controlling anthropogenic sources of CO_2 will likely be expensive and politically difficult to implement.

It has been estimated that 469 megatonnes of CO_2 were emitted in Canada in 1987, of which approximately 20% originated from fossil fuels consumed in generating electricity. By the year 2005, the forecast production will be approximately 668 megatonnes. At the Toronto conference, a 20% reduction from 1988 levels was called for, or a 47% reduction from the levels projected for the year 2005.

Because approximately 30% of Canada's power is generated by burning fossil fuels, there is a large capital investment in associated equipment. Carbon dioxide emission controls would substantially increase capital and operating costs, and subsequently, the cost of power generated. The following sections outline the estimated costs of removing and disposing of CO_2 from flue gases produced by power utilities fired by fossil fuels.

1.2 Technical Approach

Potential CO_2 removal and disposal technologies were surveyed, focusing on readily available information from recognized experts in the field. The cost and performance of each technology, its applicability to Canadian electric power systems, its secondary impacts, and the accuracy or completeness of the technical information were evaluated. Cost data obtained were converted to 1989 Canadian dollars.

1.3 Summary of Carbon Dioxide Removal Technologies

The five CO_2 removal technologies evaluated in this report are solvent absorption, direct oxygen firing in CO_2, brine absorption, condensation/cryogenic distillation, and solid adsorption. These are summarized in Tables 4 to 8.

Capital and operating costs were developed only for solvent absorption (chemical and physical), and direct oxygen firing. Costs were not found for brine absorption and solid adsorption, probably because these technologies have not been commercially demonstrated on power plant flue gases. Costs were not developed for condensation because it is estimated that it consumes more than 50% of the power produced by the plant and is thus prohibitively expensive.

There are many solvent absorption processes in commercial use for removing CO_2 from low oxygen gas streams, e.g., natural gas and refinery gas streams. Some of these processes have been used to recover CO_2 from fossil-fuel flue gas, but only when these flue gas streams were free of sulphur dioxide (SO_2). The presence of SO_2 significantly increases degradation of many solvents. This is the case for the monoethanolamine (MEA) and FS-1L chemical solvents and, to a lesser extent, the Selexol physical process.

Costs for flue gas desulphurization (FGD) are included in this report in case SO_2 must be removed to obtain acceptable performance on oil- and coal-fired boiler flue gases.

Direct oxygen firing, replacing the air supply of furnaces with a combination of oxygen and flue gas, has had limited commercial-scale testing. This process uses oxygen combined with the combustion flue gases to combust the fossil fuels in existing boilers. Because no atmospheric nitrogen is introduced into the boiler, the combustion flue gases are predominately CO_2 and H_2O and separation of the CO_2 from the flue gas is simplified. The major cost of this process is the air liquefaction plant needed to separate nitrogen from atmospheric oxygen. Because cost data were available, cost estimates were developed for this technology. Fossil-fuel-fired boilers are not designed for oxygen firing, however, and retrofitting for this technology may therefore include a significant number of limitations on the boiler-operating process that may restrict its application.

1.4 Summary of Carbon Dioxide Disposal Technologies

The five CO_2 disposal technologies evaluated in this report are injection into existing and depleted oil fields, deep ocean injection, brine solids precipitation and disposal, salt dome injection/storage, and algae pond injection. These technologies are summarized in Tables 7 to 13. Capital and operating costs include the cost of transporting CO_2.

Injection into either existing or depleted oil and gas fields and into deep oceans were found to be the most feasible methods. Power plants in Alberta and Saskatchewan would be relatively close to oil and gas fields, and those near the east and west coasts would be within 350 to 450 km of the ocean.

Another method that may have significant potential for Canada is brine scrubbing followed by precipitation and disposal of the carbonate (CO_2-containing) solids. Significant deep brine aquifers may exist in Saskatchewan and Alberta and could be pumped to power plants in nearby provinces or CO_2 could be transported to the brine aquifers (Ogu and Arnold, 1989). The interaction of CO_2 with dissolved minerals is a complex area, however, that is just beginning to be examined. The carbonate solids generated would likely be separated from the spent brine before reinjection of the brine to prevent plugging of the aquifer. The solids could then be disposed of in a similar

Table 4 Solvent Absorption (Chemical and Physical)

DESCRIPTION OF PROCESS: A packed-bed absorber provides countercurrent contact of liquid and gas. Solvent reacts with CO_2 to form a complex. The CO_2 is recovered from the solvent using heat and/or depressurization. The solvent is returned to the liquid/gas contactor.

DEVELOPMENT STATUS: Well developed, widely used process on low SO_2. Solvents are poisoned by SO_2. The only commercial application on coal-fired boiler flue gases uses a conventional sodium scrubber for SO_2 removal before CO_2 is absorbed.

CONTROL EFFICIENCY: >90%

PROCESS ISSUES: Corrosion and solvent poisoning due to SO_2. Many processes cost-sensitive to CO_2 partial pressure (%CO_2).

INDIVIDUAL PROCESSES:

Solvent	Type	Brand/Company	% Eff	Issues
MEA (monoethanolamine)	chemical	Dow Union Carbide	>95%	Used with coal-fired (SO_2 removal) and natural gas. No limit on inlet %CO_2.
Carbonate	chemical	Benfield (Union Carbide); Catacarb (Eikmeyer & Associates); Giammarco-Vetrocoke (Davy McKee)	>99%	Corrosion inhibitor - best for high %CO_2. Corrosion inhibitor - best for high %CO_2. Corrosion inhibitor - no limit on inlet %CO_2.
Dimethyl ether of polyethylene glycol	physical	Selexol (Norton)	>95%	Best for high inlet %CO_2. (18% CO_2 and greater).

ESTIMATED COSTS: Selexol Process - 11 630 t/day, Capital - $\$258 \times 10^6$
O&M - \$15.2/t of CO_2, Power - 291 kWh/t of CO_2

APPLICABILITY: No major restrictions other than those mentioned under process issues.

Table 5 Direct Oxygen Firing/Carbon Dioxide Recycle

DESCRIPTION OF PROCESS: Air is partially liquefied to produce pure nitrogen and pure oxygen. Recycled flue gas (93% CO_2) is combined with enough oxygen (70% CO_2 and 30% O_2) to burn coal at normal boiler temperatures and produce a nearly pure (95% CO_2) gas stream after drying.

DEVELOPMENT STATUS: Pilot, stoker boiler retrofit, and process evaluation research.

CONTROL EFFICIENCY: 100%

PROCESS ISSUES: Flame temperature, CO_2/O_2 ratio, flue gas/O_2 recycle ratio, safety, air inleakage, and additional fan capacity for flue gas return. Boiler corrosion due to high SO_2/CO_2 concentrations.

ESTIMATED COSTS: 12 639 t/day, Capital - $\$247 \times 10^6$
O&M - \$11.22/t, Power - 237 kWh/t of CO_2

APPLICABILITY: May result in derate of some boilers.

Table 6 Brine Absorption

DESCRIPTION OF PROCESS: The flue gas is contacted with brine in an absorber and the CO_2 reacts with alkali metals, similar to limestone flue gas desulphurization, to produce solid precipitates of calcium or magnesium carbonate, bicarbonate, or sulphate.

DEVELOPMENT STATUS: Theoretical, based on SO_2/brine studies for flue gas desulphurization and CO_2/brine laboratory studies at atmospheric pressure and temperature.

CONTROL EFFICIENCY: >92% for sea water/CO_2 system.

PROCESS ISSUES: Alkaline solution (pH>5) required to promote precipitation. Very high liquid-to-gas ratios may be required to obtain removal efficiencies.

ESTIMATED COSTS: None found.

APPLICABILITY: Saskatchewan and Alberta may have significant brine aquifers. Sea water available for coastal provinces.

Table 7 Condensation/Cryogenic Distillation

DESCRIPTION OF PROCESS: Inlet gas is dried and compressed, then refrigerated in a condenser column to recover liquid CO_2. Ryan-Holmes (RH) process uses an additive resulting in condensation at higher temperatures (less refrigeration).

DEVELOPMENT STATUS: Used to remove CO_2 in methane/CO_2 mixtures and natural CO_2 used in enhanced oil recovery. Many commercial engineering firms are reported to provide service.

CONTROL EFFICIENCY: Straight distillation - 70 to 85%

PROCESS ISSUES: RH recommends 20% CO_2 inlet gas streams. Compression/ refrigeration requires high energy input.

ESTIMATED COSTS: None found. However, power requirements have been estimated at 70% of plant capacity.

APPLICABILITY: No major restrictions except very high plant derate due to power requirements.

Table 8 Solid Adsorption/Molecular Sieve Control

DESCRIPTION OF PROCESS: CO_2 is adsorbed or captured by solid. After contact, CO_2 is desorbed to regenerate sorbent or disposed with spent solid.

DEVELOPMENT STATUS: Natural zeolites (alumino-silicates) have been used for SO_2 removal. Little information available on adsorption capacity of natural or molecular sieve substances for CO_2.

CONTROL EFFICIENCY: May require significant amounts of sorbent to obtain high removal efficiencies.

PROCESS ISSUES: An adsorbent regeneration step must be included when synthetic adsorbents are used. Use of natural adsorbents would require mining and disposal of large amounts of adsorbent.

ESTIMATED COSTS: None found.

APPLICABILITY: Availability of large deposits of mineable natural zeolites is limited.

Table 9 Enhanced Oil Recovery/Depleted Oil Field Injection

OPERATING PRINCIPLE: CO_2 is injected in the dense phase under pressure 13 790 kPa (2 000 psi) into existing or abandoned oil or gas fields. Displacement front forces oil and water from the source rock capillaries.

DEVELOPMENT STATUS: Common practice in the U.S. for enhanced oil recovery.

ENVIRONMENTAL CONCERNS: Groundwater contamination; geologic instability; pipeline impacts.

ESTIMATED COSTS: Based on costs for a 50 168 t/day pipeline
Capacity - 50 168 t/day, Capital - $258 900/km
O&M - $0.0023/(t·km)
Power - 0.045 kWh/(t·km)

Table 10 Deep Ocean Injection

OPERATING PRINCIPLE: Pressurized 13 790 kPa (2 000 psi), dense phase CO_2 is pumped to ocean depths >3 000 metres. At this depth, CO_2 is more dense than sea water and is expected to sink to the ocean bottom without dissolving or dispersing in sea water.

DEVELOPMENT STATUS: This technology is hypothetical. Some conjecture exists in the literature as to its feasibility.

ENVIRONMENTAL CONCERNS: Stability of liquid CO_2 pools on the ocean bottom; CO_2 dissolved in sea water increases alkalinity, which would be detrimental to deep ocean biotic communities; pipelines from sources to ocean will cross coastal areas likely to contain wetlands and other sensitive biotic communities; effects on fisheries unknown, but of concern.

ESTIMATED COSTS: Based on costs for 153 504 t/day pipeline
Capacity - 153 504 t/day, Capital - $916 608/km
O&M - $0.0013/(t·km)
Power - 0.026 kWh/(t·km)

APPLICABILITY: Deep ocean relatively short distance off the east/west coasts.

Table 11 Brine Precipitate/Reinjection

OPERATING PRINCIPLE: CO_2 is removed from the flue gas when passed through natural brines. The brine is reinjected into the ground after carbonates are precipitated out. Precipitated carbonates are sold for commercial use and/or disposed of in a similar manner to FGD solid waste.

DEVELOPMENT STATUS: Removing CO_2 from flue gas streams with natural brines has received little attention.

ENVIRONMENTAL CONCERNS: Disposal of carbonate solid waste; land use for precipitation ponds; pipelines for either bringing CO_2 to the brines or vice versa may cross environmentally sensitive areas.

APPLICABILITY: Most suitable for utilities located near brine deposits.

COSTS: None found.

Table 12 Salt Dome Injection

OPERATING PRINCIPLE: Salt deposits (domes) are excavated/leached using fresh water; brine is removed, leaving storage cavity.

DEVELOPMENT STATUS: Widely used commercially in U.S. for petroleum storage.

ENVIRONMENTAL CONCERNS: Brine disposal - some minerals in the brine are commercially useful, but 80 to 90 million barrels of brine are generated for a cavity with a capacity of 10 million barrels. Extensive studies have been done of environmental effects of brine disposal in the Gulf of Mexico - no significant effects found; pipelines may cross environmentally sensitive areas.

APPLICABILITY: Not considered feasible due to the large amount of storage capacity needed to significantly reduce CO_2 emission.

COSTS: Reported costs not applicable.

Table 13 Algae Pond Injection

OPERATING PRINCIPLE: CO_2 stream is pumped into artificial ponds to stimulate growth of algae, and subsequent photosynthesis ($CO_2 + H_2O + UV \rightarrow CH_2O + O_2$). Certain algae species produce large amounts of lipids appropriate for conversion to diesel fuel.

DEVELOPMENT STATUS: A long-term option. Technology expected to reach marketplace in 2020. EPRI research shows 8.5 square miles (22.1 km^2) required to remove CO_2 from a 500-MW plant.

INPUT CHARACTERISTICS: Current prototypes use pure CO_2; flue gas constituents may be toxic to algae.

APPLICABILITY: Light is the limiting factor for algae production. This is a particular problem in Canada, as is the short growing season.

COSTS: Reported costs not applicable.

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manner to conventional sludges from flue gas desulphurization units. This option may warrant further study to determine the cost of brine transportation, scrubbing, solids separation, and sludge disposal.

The other two disposal options evaluated were not considered applicable to Canada. Salt dome storage would require vast amounts of fresh water to create the salt domes with the resulting salt water being injected into the ocean. Conversion of CO_2 to biomass in algae ponds would not be applicable to Canada due to the ultraviolet light requirements and the land area needed. The short days and low light intensity during winter would prevent effective conversion for much of the year, and the land area required is impractical even at lower latitudes. Research is currently being conducted into the use of fibre optics tubes to reduce the land requirement (Campbell, 1989).

Section 2

Carbon Dioxide Removal Technologies

In this section, the operating principle and process are explained for each CO_2 removal technology and the current developmental status discussed. Estimates for control efficiency from the literature are reported, as well as the process issues and waste stream characteristics.

2.1 Solvent Absorption

The solvent absorption process uses classical chemical engineering principles of liquid/gas interaction for absorption and desorption/recovery of CO_2. There are two types of liquid absorbents: chemical and physical. Two specific examples of chemical solvents are organic amines and carbonates. A commercially available physical solvent process uses ether. Methanol has also been used as a physical solvent for CO_2 (Steinberg, 1983; Shah and McFarland, 1988; Ogu and Arnold, 1989).

2.1.1 Chemical Absorption with Monoethanolamine

In this process, a packed bed absorber is used for countercurrent contact of liquid monoethanolamine (MEA) with flue gas (Steinberg, 1983; Ogu and Arnold, 1989; Arnold *et al.*, 1982). Monoethanolamine reacts with CO_2 to form a stable chemical complex. Carbon dioxide is recovered by steam stripping the spent solvent to regenerate MEA for return to the absorbing column. Figure 2 illustrates the MEA absorption process without prior flue gas desulphurization (FGD).

Monoethanolamine absorption is a well developed technology for CO_2 recovery and is widely used with coal synthesis gas and natural gas (Shah and McFarland, 1988; Sparrow *et al.*, 1988). In 1982, a Kerr-McGee Unit in Searles Valley, California successfully used MEA at a coal-fired power plant for enhanced oil recovery (EOR) disposal of the collected CO_2. However, the SO_2 was removed before CO_2 absorption using a conventional sodium wet scrubber (Vandenhengel and Stright Jr., 1979; Arnold *et al.*, 1982). In 1982, a natural gas-fired power plant in Lubbock, Texas, used a similar alkanolamine for CO_2 removal in EOR operations that was reported to be the first large-scale flue gas/CO_2 separation facility in the world (Pauley, 1984).

The control efficiency of MEA absorption is reported to be <95%. There is no lower limit on the concentration of CO_2 in the influent gas, although high concentrations of CO_2 and lower O_2, H_2O, SO_2, and NO_x are preferred. A corrosion inhibitor is needed if sulphur compounds are present. Poisoning of amine solvents by SO_2 makes MEA unsuitable for SO_2-containing streams. The CO_2-rich outlet gas from the MEA absorbing unit would be compressed and dried for transport and disposal. (Steinberg *et al.*, 1984; Shah and McFarland, 1988; Ogu and Arnold, 1989; Sparrow *et al.*, 1988; Vandenhengel and Stright Jr., 1979; Wolsky *et al.*, 1985; Arnold *et al.*, 1982; Wolsky and Brooks, 1988.)

2.1.2 Chemical Absorption with Hot Carbonate

This absorption process (see Figure 2) uses a packed bed or tray absorber to provide

countercurrent contact of hot liquid carbonate with the flue gas (Shah and McFarland, 1988; Arnold *et al.*, 1982). The hot carbonate reacts with CO_2 to form a stable chemical complex. Activators or catalysts, such as arsenic trioxide or amine borates, are added to improve kinetics and, consequently, reduce the column size as compared to conventional solvent systems. Regeneration of the hot carbonate uses less steam than other chemical solvents, some using only air stripping. The catalysts also provide corrosion inhibition, which is important for continuous operation.

Commercial hot carbonate systems include the Benfield process (Union Carbide), the Catacarb process (Eikmeyer and Associates), and the Giammarco-Vetrocoke process (Davy McKee). The control efficiency is reported to be >99% for these methods. The Benfield and Catacarb processes are sensitive to CO_2 partial pressure while the Giammarco-Vetrocoke process is not. (Shah and McFarland, 1988; Ogu and Arnold, 1989; Sparrow *et al.*, 1988.)

Hot carbonate absorption of CO_2 produces an exit gas with a high concentration of CO_2 at atmospheric pressure. The waste stream needs to be compressed for transport and disposal (Sparrow *et al.*, 1988).

2.1.3 Physical Absorption with Selexol

Selexol, a dimethyl ether of polyethylene glycol, physically dissolves CO_2 at low temperatures and high pressures in a packed column. Air stripping or flashing (depressurization) into drums at atmospheric pressure is used to regenerate the solvent; no

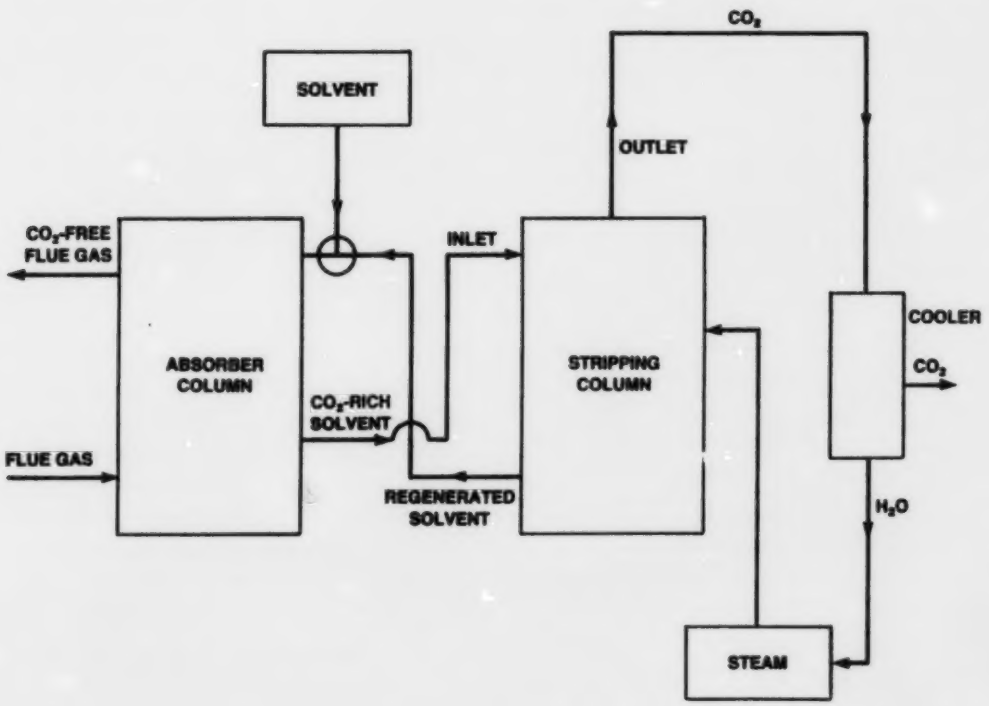

Figure 2 Chemical Solvent Absorption

heat is necessary in the stripping process (Shah and McFarland, 1988; Sparrow *et al.*, 1988). The CO_2 stream can be dehydrated easily since water is not introduced as steam in this process . A typical Selexol process for CO_2 recovery is shown in Figure 3.

Selexol can be obtained from Norton Chemical Company (Shah and McFarland, 1988). This process has been used for removing CO_2 and reduced sulphur compounds (H_2S, COS, etc.); for ammonia purification after synthesis from methane; for coal gasification synthetic gas cleaning; and for natural gas desulphurization to "sweeten" the gas. More than 40 plants in the United States now use Selexol for removing CO_2. Most applications have been for inlet gas streams with a high percentage (more than 20%) of CO_2 and with little or no SO_2. (Shah and McFarland, 1988; Ogu and Arnold, 1989.)

The CO_2 removal efficiency with Selexol is reported to be >97% for inlet stream of 18% CO_2. The Selexol solution itself is non-corrosive and since SO_2 has a much lower solubility than CO_2 (roughly 1/100) in Selexol, interference and/or corrosion by dissolved SO_2 is less likely than for amine and carbonate systems (Shah and McFarland, 1988).

2.2 *Direct Oxygen Firing with Carbon Dioxide Recycle Boilers*

In direct oxygen-fired CO_2 recycle boilers, ambient air is liquefied and separated into pure nitrogen and pure oxygen (79% nitrogen and 21% oxygen). Recycled flue gas (91% CO_2) is combined with enough oxygen (70% CO_2 and 30% O_2) to burn coal at normal boiler temperatures to produce a nearly pure (95% CO_2) gas stream after drying (Wolsky *et al.*, 1988). This process is illustrated in Figure 4.

Test-scale, pilot-scale, and full-scale utility (retrofit) research, as well as process evaluation studies, have been performed (Steinberg, 1983; Wolsky *et al.*, 1988;

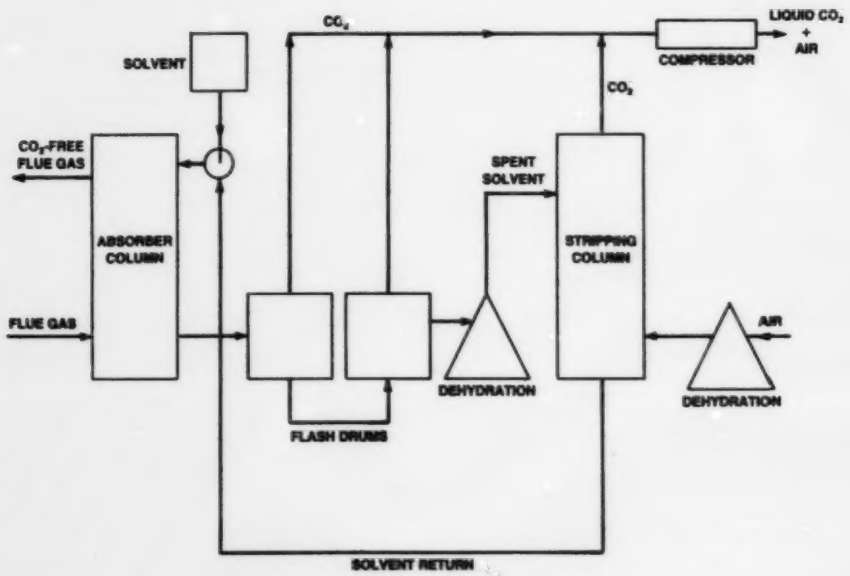

Figure 3 Physical Solvent Absorption

Wolsky and Brooks, 1988; Sparrow *et al.*,1988; Wolsky, 1986). Tests using a 0.4 MBtu/h* pulverized coal combustor were performed in 1985 by Batelle Columbus and Argonne National Laboratory. Pilot-scale tests with a 10 MBtu/h tower furnace were performed in 1987 using subbituminous coal. A 2 MBtu/h stocker-fired boiler was retrofitted for recycling CO_2 at the Black Hills Power and Light Plant in Rapid City, South Dakota and tested with subbituminous coal in 1986. (Wolsky and Brooks, 1988; Sparrow *et al.*, 1988.)

The control efficiency for this process is 100% since CO_2 is contained within the system. The critical process issues are flame temperature, CO_2/O_2 ratio, and flue gas/oxygen recycle ratio. These issues have been studied for coal boilers (Wolsky *et al.*, 1985; Wolsky *et al.*, 1988; Sparrow *et al.*, 1988). Other concerns are safety, air inleakage, and additional fan capacity for flue gas return (Wolsky and Brooks, 1988). No noticeable effect was observed on coal combustion, steam production, and coal-feed/ash handling systems in the tests. Coal-fired boilers vary significantly in their design and operating characteristics,

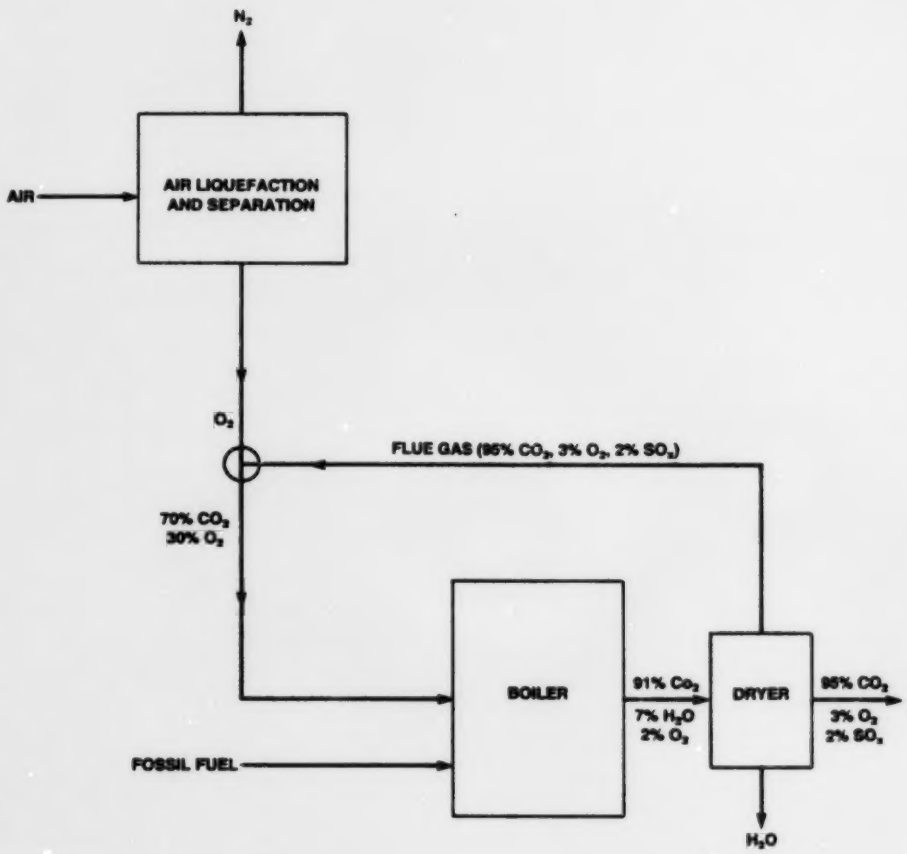

Figure 4 Carbon Dioxide Recycle Boilers

* 1 Btu = 1.055 056 kJ

however, and these results cannot be extrapolated to all boilers. It is likely that some boilers would be derated after retrofit due to heat transfer section imbalances. Without extensive testing and evaluation, the number of boilers that would experience serious operating problems cannot be estimated. Boiler corrosion may also be a problem due to the high CO_2 and SO_2 concentrations in the presence of moisture from combustion.

After drying, a flue gas of 95% CO_2, 3% O_2, and 2% SO_x and NO_x is produced for compressing and transporting through pipeline to a disposal site (Wolsky and Brooks, 1988).

2.3 Brine Absorption

Carbon dioxide will react with brine components (calcium, Ca; magnesium, Mg; sodium, Na; potassium, K; etc.) to form stable chemical compounds, principally sodium carbonate (Na_2CO_3), magnesium chloride ($MgCl_2$), magnesium carbonate ($MgCO_3$), and calcium carbonate ($CaCO_3$). This principle has been explored for the recovery of minerals from brines for commercial development (Ogu and Arnold, 1989). A possible flue gas/brine absorption system for the recovery of CO_2 is shown in Figure 5.

In this system, flue gas is contacted with brine in an absorption column or spray tower designed to maximize gas-liquid contact and the gas/liquid ratio and, therefore, to minimize tower size. The CO_2 in the flue gas reacts with the alkali minerals, in a process similar to limestone flue gas desulphurization, to produce precipitates of Ca or Mg carbonates and bicarbonates that may be marketable. For example: calcium carbonate is used commercially in latex paints, resins, adhesives, and rubber; magnesium carbonate is a main ingredient in cosmetics; and magnesium chloride is used to manufacture magnesium metal.

The use of brine for removal of gases from process streams has been explored theoretically for flue gas desulphurization and in CO_2/brine laboratory studies at atmospheric pressure and temperature. A patented process for removing CO_2 from natural gas, designed to sit on the ocean floor, has been used by Phillips Petroleum Company (U.S. Patent, 1980). The capture efficiency of this process was reported to be >92% for a sea water/natural gas system, and it is reported to be applicable to 10 to 20% CO_2 gas streams (Ogu and Arnold, 1989).

In laboratory experiments performed with brine and CO_2, an alkaline solution (pH>5) was necessary for precipitation of the mineral brine/CO_2 complex. Precipitation may not be necessary for flue gas cleaning; complexation may be sufficient for capturing CO_2, depending on the solubility of the mineral carbonates in brine or the recycle stream. Spray reactors may afford good gas/brine contact, although very high liquid-to-gas ratios may be required to obtain the desired removal efficiencies (Wolsky and Brooks, 1985). Research has not been carried out on the necessary liquid-to-gas ratios. If very high liquid-to-gas ratios are necessary, the process may not be economically feasible. The brine/CO_2 waste stream characteristics will be a solution, slurry, or mud of mineral carbonates, depending on the process (Ogu and Arnold, 1989).

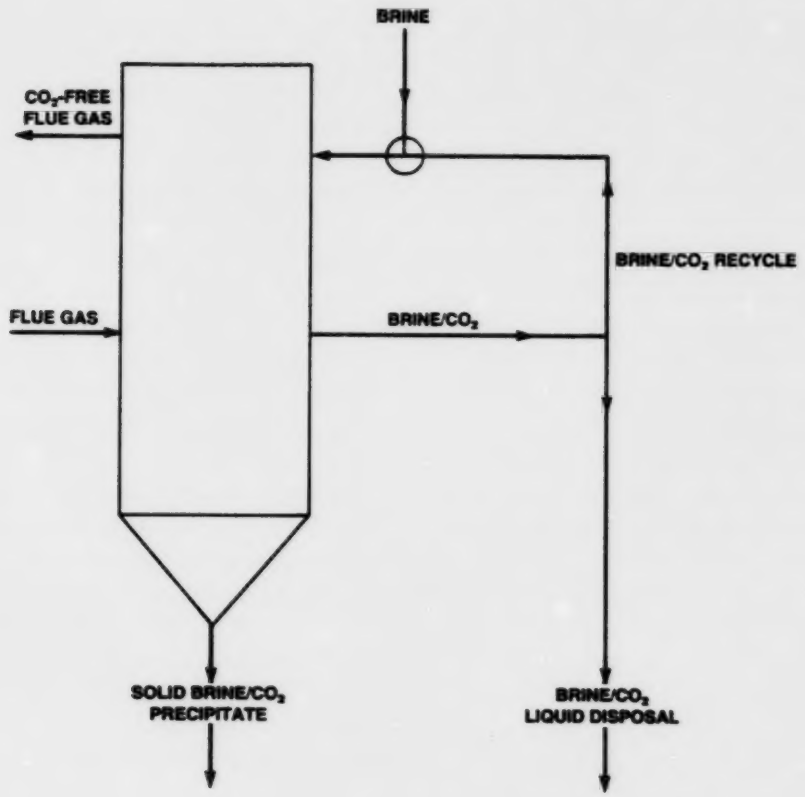

Figure 5 Brine Absorption

2.4 Condensation/Cryogenic Distillation of Carbon Dioxide from Flue Gas

At low temperatures and high pressure, CO_2 can be condensed and separated from less condensible gases. A condensation/ cryogenic distillation (CCD) process for removing CO_2 is shown in Figure 6. The flue gas is dried and compressed at the inlet and the dried gas is then refrigerated in a condenser column to recover liquid CO_2. One CCD process, commercially available from Ryan-Holmes, uses an additive to enhance distillation at higher temperatures. (Wolsky and Brooks, 1985.)

Condensation/cryogenic distillation has been used to remove CO_2 from methane/CO_2 mixtures and from the gases used for flooding in enhanced oil recovery. It is reported that many commercial engineering firms provide this service. In 1984, Koch Process Systems in Westborough, Massachusetts, had licenses for seven applications of CCD for CO_2 from process streams, one of which was through Amerada Hess Corporation in Seminole, Texas. (Sparrow *et al.*, 1988; Wolsky and Brooks, 1985.)

Control efficiency for the "straight" distillation CCD process is reported to be from 70 to 85%. The Ryan-Holmes process is reported to achieve better collection than

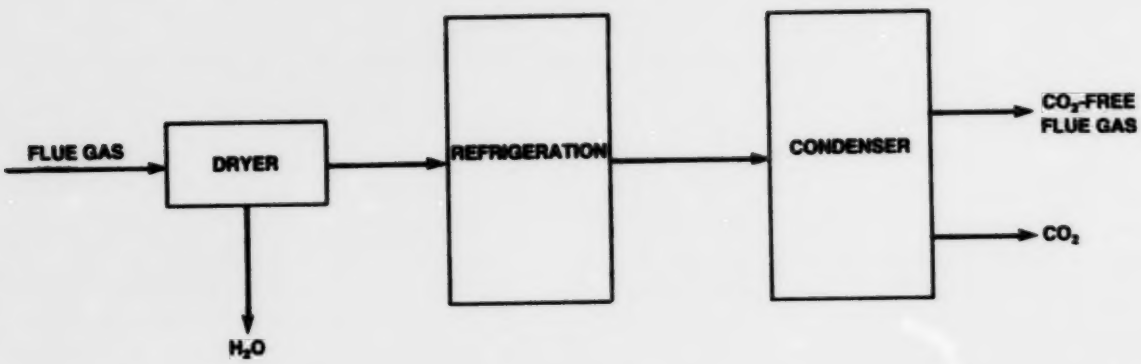

Figure 6 Condensation/Cryogenic Distillation

straight distillation. Condensation/cryogenic distillation requires a high energy input when the CO_2 concentration in the inlet gases is low . The Ryan-Holmes process is recommended for inlet gas streams with CO_2 concentrations >20%. In CCD, the process stream will contain all condensible gases, including SO_2 if present in the flue gas. Corrosion is avoided by drying of the inlet gas. (Wolsky *et al.*, 1985; Wolsky and Brooks, 1985.)

2.5 Solid Adsorption (Molecular Sieve)

In solid adsorption, CO_2 is captured by the solid due to the properties of the adsorbent or pore size, as in molecular sieves (Ogu and Arnold, 1989). One adsorbent that may have promise in CO_2 recovery is natural or synthetic zeolite (Steinberg, 1983). Diatomaceous earth is one source of natural zeolite.

An example of an adsorption process is shown in Figure 7. In this process, flue gas containing CO_2 is passed through and captured by an adsorbing column that allows for good gas/solid contact. A spray dryer may also be used to achieve this goal more effectively. In the second stage, CO_2 is either desorbed from the zeolite to regenerate the solid or disposed with the spent solid as a solid waste.

If solid adsorption is used for removing CO_2, a dual system is recommended to avoid downtime while the adsorption units are operating. An adsorbent regeneration step is especially preferred if expensive synthetic zeolites are used. (U.S. EPA, 1985; Steinberg, 1983.)

Natural zeolites (alumino-silicates) have been used for SO_2 removal. Little is reported on the CO_2 adsorption capacity of natural substances, except for comments on the possibly poor capacity of zeolites (U.S. EPA, 1985; Steinberg, 1983; Ogu and Arnold, 1989.)

Regeneration of solid adsorbents produces a concentrated CO_2 stream that must be compressed for transport and disposal. Considering the large volume of earth that would be required and the costs of transporting it, the use of natural adsorbents is probably not ecologically desirable. In addition, there are no substantial deposits of diatomaceous earth in Canada.

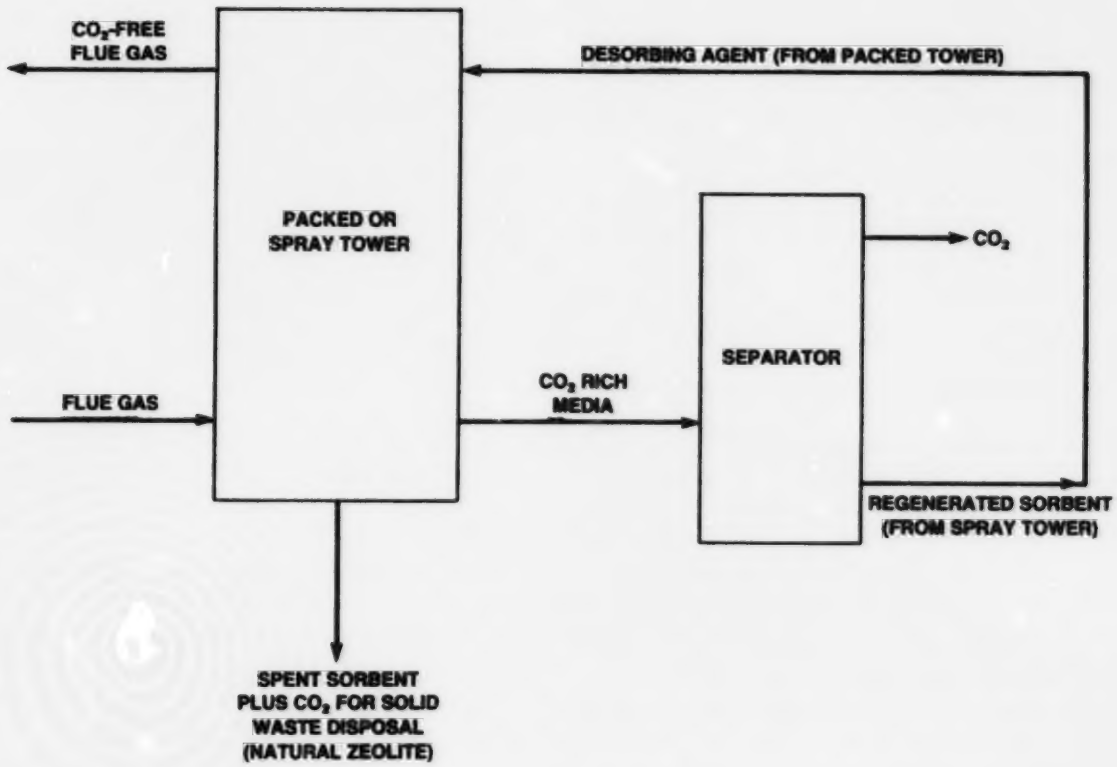

Figure 7 **Solid Adsorption/Molecular Sieve**

Section 3

Carbon Dioxide Disposal Technologies

Technologies considered for disposing of CO_2 include terrestrial storage, deep ocean disposal, reaction with naturally occurring brines, and algae pond injection. The feasibility and environmental effects of the terrestrial storage technologies, such as injection into depleted oil wells and storage in excavated salt domes, were estimated based on similar proven technologies, such as CO_2-enhanced oil recovery and petroleum storage in salt domes. Deep ocean disposal, reaction with brines, and algae pond injection, however, remain hypothetical technologies; their feasibility and effects are not as well documented.

3.1 Enhanced Oil Recovery (EOR) and Depleted Well Injection

Primary extraction removes about one-third of the oil in a well; another third can be removed through enhanced oil recovery (EOR) techniques. Enhanced oil recovery through CO_2 flooding is common practice in the United States, particularly in the Gulf Coast states. Enhanced oil recovery projects are also ongoing in Alberta but using primarily hydrocarbon solvent, not CO_2. Projects in Alberta using CO_2 consist of one pilot and one commercial operation. Carbon dioxide is desirable for EOR because its high solubility in oil markedly reduces the oil's viscosity and density and makes it more mobile in the rock formation (Horn and Steinberg, 1981).

Natural deposits are the current source of CO_2 for EOR in the U.S. The CO_2 is pipelined to the oil fields under 15 168 kPa (2 200 psi) pressure and injected into the wells. When the CO_2 comes in contact with the oil, some of the hydrocarbons in the oil vaporize and mix with the CO_2, forming a displacement front. As more CO_2 is pumped into the well, the front moves through the rock, forcing the oil before it (Krickenberger and Lubroe, 1981). Approximately 170 to 1 100 kg of CO_2 are required to recover 1 barrel* of oil, depending upon factors such as rock type, degree of well depletion, and original size of reservoir (Pechtl, 1989).

The U.S. National Petroleum Council has referred to CO_2 flooding as the technique of preference for EOR and predicts that oil production by CO_2 flooding will surpass thermal recovery by the year 2007. These projections are based on the use of natural sources of CO_2. In the U.S., anthropogenic sources of CO_2 remain relatively untried. (Cobb *et al.*, 1988; Wolsky *et al.*, 1985.) Enhanced oil recovery requires 90 to 98% pure CO_2 injected at about 13 370 kPa (2 000 psi) (Krickenberger and Lubroe, 1981; Oil and Gas Journal, 1982). The cost of recovering CO_2 from flue gas and purifying it tends to be the limiting factor in EOR, rather than any feasibility problems associated with CO_2 transport and well injection.

Injecting CO_2 into depleted oil and gas wells for permanent storage would probably use technologies identical to EOR. Only 20 to

* 1 barrel = 0.159 m^3

50% of the CO_2 injected for EOR, however, remains in the reservoir. Injection of CO_2 for EOR has not been designed to maximize CO_2 storage. Improved capping and recovery/reinjection of CO_2 from the recovered oil and water could significantly increase this percentage (Pechtl, 1989).

Environmental Effects. In the U.S., EOR by CO_2 flooding occurs primarily in Texas, Louisiana, and California, where permits or hearings are required. The primary environmental concern in EOR projects is the protection of groundwater. The geologic stability of the area proposed for EOR is also a consideration and, in coastal areas of California, an environmental review is a prerequisite to granting EOR permits.

Environmental concerns generally focus on the impact of oil recovery and the possibility of leaks or spills. The effects of long-term CO_2 storage have not been considered by agencies issuing permits. Corrosion of the casing, caused by carbonic acid formed from water-CO_2 reaction, however, would become an issue with permanent CO_2 storage. Because EOR disturbs roughly one-third of the total area in a well pattern (Haynes *et al.*, 1978), other possible secondary effects include loss of vegetation, habitat destruction, and subsequent soil erosion. The surface impact could be reduced with directional drilling, which would reduce the number of wells required to drain the reservoir. Appropriate monitoring is also necessary to ensure that well capping and casing remain intact.

3.2 Deep Ocean Disposal

Disposing of recovered CO_2 in the deep ocean is a hypothetical option whereby liquid CO_2 under 13 790 kPa (2 000 psi) pressure is piped to ocean depths of 3 000 m or greater. At this depth, CO_2 is denser than sea water and is expected to sink to the ocean bottom without dissolving or dispersing in the sea water. While this disposal technique is untried, there is conjecture in the literature that the ocean provides a significant untapped sink for atmospheric CO_2 and that CO_2 would be retained for hundreds or thousands of years (Steinberg *et al.*, 1984; Baes *et al.*, 1980).

Environmental Effects. Deep ocean disposal would be most practical where ocean depths of 3 000 m and greater occur relatively close to shore. Pipelining the liquid CO_2 to sufficient depths is probably technologically feasible; however, the long-term environmental effects of large volumes of liquid CO_2 in the deep ocean have not been studied. Of particular concern are CO_2 saturation of different strata in the ocean, deep water nutrient cycling, and ocean circulation patterns.

As dissolution of CO_2 would increase the alkalinity of the sea water, it is not known if the sunken pools of liquid CO_2 would remain stable. Changes in the alkalinity of sea water could have profound effects throughout the biotic and abiotic systems of the ocean. Potential effects on fisheries are of primary concern. (Steinberg *et al.*, 1984; Baes *et al.*, 1980; Takashi, 1989; Horn and Steinberg, 1981.)

In Canada, ocean depths of 3 000 m or greater are found in the Atlantic approximately 400 km off the coast of Nova Scotia in the Sohn Abyssal Plain and 1 000 km off the coast of Newfoundland in the Newfoundland Basin, and in the Pacific, about 1 000 km off the west coast in the Tufts Abyssal Plain.

3.3 *Brine Precipitation and Reinjection*

The use of naturally occurring brines has been considered for removing CO_2 from flue gas streams. This would require disposing of large quantities of spent brine. The interaction of CO_2 with dissolved minerals is complex and just beginning to be examined. Brine produced as waste by various mining activities has traditionally been reinjected into deep wells with no apparent adverse effects. Presumably, brine that has been used to treat flue gas could also be injected into deep wells. Injecting solid precipitates in suspension into an aquifer, however, would very likely cause plugging that would result in decreased porosity/permeability of the aquifer.

The flue gas constituents expected to react with brine are SO_2 and CO_2 (Ogu and Arnold, 1989). Carbonates, sulphates, and bicarbonates would be the resultant precipitates. These precipitates could be separated from the brines in precipitate ponds, as discussed with salt dome excavation, or they could be reinjected into the ground along with the brine. In the case of precipitate ponds, there is, again, a solid waste disposal problem. As discussed in Subsection 2.3, some of the products of CO_2 removal and precipitation, particularly calcium and magnesium carbonates, have commercial value, although existing demand would dispose of only a fraction of the precipitates produced (Dunsmore, 1989).

3.4 *Salt Dome Injection*

Salt domes are columns of rock salt that form from underlying salt beds. Plastic flowing salt moves upward through denser surrounding sedimentary rock. The salt column is slightly convex at the surface, hence the term "dome" (Davis, 1981). For purposes of storage, a cavern is excavated in the column by injecting water and removing the resultant brine. About six to seven barrels* of water are required to leach one barrel of storage space.

Since 1975, the U.S. National Strategic Petroleum Reserve project has built storage facilities for approximately 290 million barrels of petroleum in salt domes in the Gulf States area. In Canada, there are significant salt deposits in New Brunswick, Nova Scotia, southwest Ontario (a small portion of the Michigan Basin), and in north central Alberta and central Saskatchewan (the Prairie evaporites). The latter deposits are the largest, occurring in beds 300 m thick in some places. Canada's salt deposits are bedded deposits rather than domes. This may be a significant factor, since salt beds occur at greater depths than domes and salt behaves like a plastic at depths greater than 300 m. Deposits in the Michigan Basin may be dense enough and close enough to the surface to accommodate excavation, but deposits in the West may be too deep.

It is hypothesized that, in a similar manner, liquid CO_2 could be permanently stored in excavated salt domes. In the U.S., it is estimated that more storage capacity exists in salt domes than in depleted oil wells. A significant fraction of the CO_2 generated by burning fossil fuel could be stored in these salt domes. Petroleum has been successfully stored in excavated salt domes since 1975 with little evidence of contamination of the oil or of adsorption on the walls of the cavern. Although there have apparently been no attempts to store CO_2 in a similar

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* 1 barrel = 0.159 m^3

manner, it should be technically feasible. There are no oil/gas storage caverns in Canada, but salt/potash beds are used in western Canada for gas storage caverns. (Steinberg, 1984.)

Environmental Effects. The primary environmental concern with salt dome injection is disposing of the brine from cavern excavation. From 1976 to 1985, the U.S. Strategic Petroleum Reserve project carried out the Oceanic Support Activity to monitor the environmental effects of brine disposal in the Gulf of Mexico. This covered the immediate area surrounding discharge and studied the status of regional fisheries, focusing primarily on shrimp populations. The results demonstrated to the U.S. Environmental Protection Agency (EPA) that no adverse environmental effects are associated with brine disposal in the Gulf. Therefore, salt dome injection may be a viable option for disposing of CO_2 providing that bodies of salt water are within a reasonable distance.

Brine could also be pumped to precipitate ponds where salts could precipitate out. There may be a limited market for some of these precipitates in the chemical industries (Ogu and Arnold, 1989). The less commercially viable salts, however, would create a solid waste disposal problem. The use of fresh water resources – 80 to 90 million barrels of water/10 million barrels of cavity – and of land for precipitate ponds, must also be considered.

3.5 Algae Pond Injection

Injection of recovered CO_2 into artificial algae ponds is a technology for transforming CO_2 into biomass. The injected CO_2 is used by the algae to produce starches through photosynthesis ($CO_2 + H_20 + UV \rightarrow CH_2O + O_2$). Certain species of algae produce significant amounts of lipids appropriate for conversion to diesel fuel (U.S. DOE, 1988; 1989), and it may be economically beneficial to produce them. Although combustion of the biomass fuel would generate CO_2, this CO_2 would be part of a short-term recycle process rather than the long-term recycle that occurs when combusting conventional fossil fuels. However, light and nutrients are limiting factors for algae growth. Nutrients, primarily nitrogen and phosphorus, would have to be added to maintain CO_2 consumption levels. Municipal wastewater is a possible source of these nutrients (U.S. DOE, 1989).

The requirement for light presents the major technological obstacle to algae pond disposal. Research into CO_2 disposal as well as biofuels production indicates that the land requirements for proper light exposure are impractical (U.S. DOE, 1988; Campbell, 1989). Using currently available technology, a 500-MW power plant would require 22.01 km^2 (8.5 square miles) of algae pond for CO_2 disposal. Fibre optics are a promising solution to the problem, but Canada's latitude and short growing season make biomass production an unlikely disposal option on a large scale (Campbell, 1989).

Environmental Effects. This disposal option seems environmentally sound, especially considering the associated production of an alternative fuel source. The transformation of large tracts of land into artificial algae ponds, however, would disturb the existing landscape and possibly eliminate important types of habitat. The use of fibre optics, if further developed, would incur an added energy penalty.

Section 4

Technology Costs

4.1 Technologies Selected for Costing

This section presents the costs and energy penalties associated with several of the removal and disposal options discussed in Sections 2 and 3. Costs are presented for various plant sizes and CO_2 capacities. This information will be used to develop cost algorithms for the CANSIM model. These cost estimates are based on published information and contacts with researchers and other experts.

Costs for some of the technologies are not reported here because similar technologies were more cost-effective, energy penalties were too great, or sufficient data were not available. For example, salt dome injection was not considered because of the potentially high excavation cost in Canada and limited potential Canadian applications.

The energy penalty associated with "straight" cryogenic distillation is estimated to be 73% of the energy produced. This is too great to consider it a viable technology (The DPA Group Inc., 1989). Enhanced cryogenic distillation, such as the Ryan-Holmes process, is viable for gases with a high concentration of CO_2. If used for flue gases with a low CO_2 concentration, however, this process would also entail a severe energy penalty (Sparrow *et al.*, 1988).

Sufficient data were not available for the following removal technologies: brine absorption and solid adsorption/molecular sieve; and for the following disposal technologies: brine precipitation and reinjection and algae pond injection.

All costs were converted to Canadian dollars (at the September 1989 rate) using the Chemical Engineering Magazine Plant Cost Index and the U.S./Canadian exchange rate published in the January 1990 U.S. Federal Reserve Bulletin.

4.2 Removal Technology Costs

Costs are reported in this section for removing CO_2 by Selexol absorption, FS-1L chemical absorption, and direct oxygen firing of boilers. Costs for flue gas desulphurization (FGD) and CO_2 compression and drying systems are also reported. The technology combinations available for CANSIM modelling are shown in Figure 8.

4.2.1 Selexol Absorption and Flue Gas Desulphurization

The costs of the Selexol process were derived for a recovery plant with a capacity of 1 276 tonnes of CO_2 per day (Shah and McFarland, 1988). Energy costs were recalculated for an electricity price of $0.047/kWh. A 0.7 scaling factor was used to determine capital costs for other plant capacities. Selexol plant costs and energy penalties are reported in Table 14.

Because corrosion and degradation problems can occur with Selexol, a flue gas desulphurization (FGD) unit may be required. These problems are less extensive with Selexol, however, than with chemical absorption systems. Using western

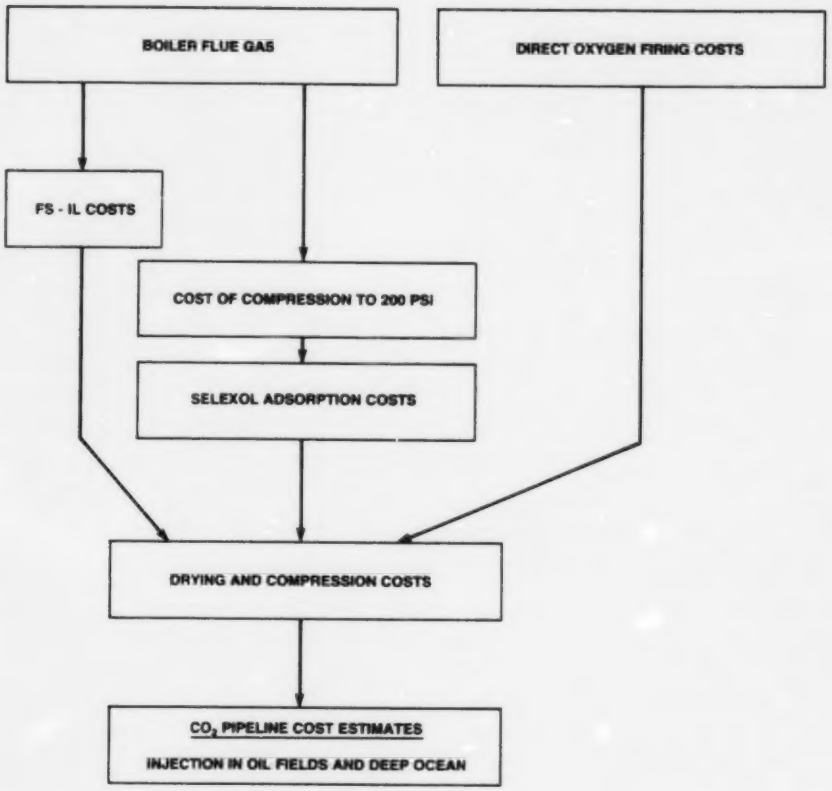

BOILER FLUE GAS
DIRECT OXYGEN FIRING COSTS
FS - IL COSTS
COST OF COMPRESSION TO 200 PSI
SELEXOL ADSORPTION COSTS
DRYING AND COMPRESSION COSTS
CO_2 PIPELINE COST ESTIMATES
INJECTION IN OIL FIELDS AND DEEP OCEAN

Figure 8 Carbon Dioxide Control Cost Scenarios

low-sulphur coal will reduce the amount of SO_2 present in the flue gas, but it will not eliminate it. The level of corrosion and depreciation occurring if SO_2 is present in the flue gas should be weighed against the cost of an FGD system.

4.2.2 FS-1L Chemical Absorption System

FS-1L is a sorbent developed by Dow Chemical Company that can be used to replace MEA in a chemical absorption system. FS-1L is more energy-efficient than MEA, requiring less electricity and heat duty (Kaplan, 1982). If steam heat can be obtained cheaply with little energy penalty, FS-1L can be more energy-efficient than the Selexol process.

In this analysis, it was assumed that steam heat could be obtained from the bottom cycle of a utility boiler resulting in a 3% efficiency reduction for the boiler (Steinberg, 1984). The electricity penalty, at \$0.047/kWh, was added to costs for water and solvent to determine total operating costs (Pauley, 1984). Costs and energy penalties are reported in Table 15.

Because corrosion and absorbent degradation problems occur with FS-1L and all chemical absorbants when used on flue gases containing SO_2, flue gas desulphurization (FGD) units must be installed on coal-fired power plants before the FS-1L process can be used economically. Costs and energy penalties for FGD systems

are not presented because it is assumed that oil/coal-fired boilers will have retrofit FGD systems to comply with acid rain controls.

4.2.3 *Direct Oxygen-fired/Carbon Dioxide Recycle Boilers*

The O_2 plant and recycle piping are the primary capital costs with direct oxygen firing (Sparrow *et al.*, 1988). The reported operating costs are for separating the O_2 from ambient air. Costs were reported for a 50-MW, coal-fired power plant emitting 1 264 tonnes of CO_2 per day. These costs were applied to other plant sizes using a 0.7 scaling factor. Costs and energy penalties for this system are reported in Table 16.

4.2.4 *Carbon Dioxide Compression and Drying*

The two CO_2 removal systems previously discussed produce a flue gas that is between 95 and 97% CO_2. This gas must be dehydrated and compressed to over 13 790 kPa (2 000 psi) before it can be economically transported through pipelines. Costs for compression/dehydration systems are reported for three sizes of systems corresponding to 500-, 100-, and 50-MW boilers (Sparrow *et al.*, 1988). Costs for other capacity systems were derived from the initial costs using a 0.7 scaling factor. Compression and drying costs and energy penalties are reported in Table 17.

4.3 *Transportation and Disposal Systems*

Pipelines are the most cost-effective method of transporting large quantities of CO_2. Studies conducted in the U.S. have examined the potential for using excess capacity natural gas pipelines to transport CO_2. Pipeline costs are reported for new pipelines on a capacity per kilometre basis. The costs and energy penalties for this method are reported in Table 18.

Multiple pipelines may be required to transport this large amount of CO_2. In determining costs for these additional pipelines, a 0.9 scale factor should be used for the capital costs of additional pipelines to avoid double counting right-of-way costs.

An adjustment factor of 1.86 was applied to the largest pipeline to estimate costs for offshore pipelines (Morgan, 1984). In any transportation scenario, CO_2 is piped to a central collection facility before being transported offshore.

For the two disposal options applicable to the Canadian situation – deep ocean disposal and disposal in active and abandoned oil and gas wells – transportation is assumed to be the major cost. Virtually all capital and operating costs are for transporting the CO_2 to the disposal site. Ninety percent of all operating costs were assumed to be energy costs (Ford, Bacon & Davis, Inc., 1985).

Table 14 Costs of Selexol Process (1989 Canadian $) (Shah and McFarland, 1988)

Plant Capacity CO_2 (t/day)	Capital Costs $ ($\times 10^6$)	Operating and Maintenance Costs* ($/t)	Energy Penalty (kWh/t)
582	33.9	15.2	291
1 163	55.0	15.2	291
2 326	89.3	15.2	291
10 582	258.0	15.2	291

* This cost includes compression costs based on information from Mr. T. Robinson, Dresser Rand Co.

Assumptions

1. Non-fuel costs converted from 1988 to September 1989 U.S. dollars using Chemical Engineering Plant Cost Index.
2. September 1989 foreign exchange rate: $1 U.S. = $1.1828 Canadian (U.S. Federal Reserve Bulletin, January 1990).
3. Capital costs scaled using a 0.7 scaling factor.
4. Electricity Cost: $.047/ kWh.
5. Accuracy range for estimates -30 to +70%.
6. Capacity factor 100%.
7. A 50-MW, coal-fired power plant produces roughly 1000 t/d of CO_2 (Steinberg, 1984).

Table 15 Costs of FS-1L Chemical Absorption Recovery System (1989 Canadian $) (Pauley, 1984; Steinberg *et al.*, 1984)

Plant Capacity CO_2 (t/day)	Capital Costs $ ($\times 10^6$)	Operating and Maintenance Costs ($/t)	Energy Penalty (kWh/t)
907.2	26.8	9.06	18.3
4 536	82.6	9.06	18.3
9 072	134.1	9.06	18.3

Assumptions

1. Non-fuel costs converted from 1988 to September 1989 U.S. dollars using Chemical Engineering Plant Cost Index.
2. September 1989 foreign exchange rate: $1 U.S. = $1.1828 Canadian (U.S. Federal Reserve Bulletin, January 1990).
3. Capital costs scaled using a 0.7 scaling factor.
4. Electricity Cost: $.047/ kWh.
5. Accuracy range for estimates -30 to +70%.
6. Capacity factor 100%.

Table 16 Costs of Direct Oxygen Firing/Carbon Dioxide Recycle System (1989 Canadian $) (Sparrow *et al.*, 1988)

Plant Capacity CO_2 (t/day)	Capital Costs \$ ($\times 10^6$)	Operating and Maintenance Costs ($/t)	Energy Penalty (kWh/t)
907.2	22.43	11.22	237
1 264	28.29	11.22	237
1 996	38.95	11.22	237
2 527	49.32	11.22	237
12 639	246.66	11.22	237

Assumptions

1. Capital costs converted from 1988 to September 1989 U.S. dollars using Chemical Engineering Plant Cost Index.
2. September 1989 foreign exchange rate: $1 U.S. = $1.1828 Canadian (U.S. Federal Reserve Bulletin, January 1990).
3. Electricity Cost: $.047 /kWh.
4. Capital costs for plants smaller than 2200 t/d were scaled from 1264 t/d using a 0.7 scale factor. Larger plants were scaled using a 1.0 scale factor.
5. Accuracy range for estimates -30 to +70%.
6. Capacity factor 100%.

Table 17 Costs of Compressing and Drying Carbon Dioxide (1989 Canadian $) (Sparrow *et al.*, 1988)

Plant Capacity CO_2 (t/day)	Capital Costs \$ ($\times 10^6$)	Operating and Maintenance Costs ($/t)	Energy Penalty (kWh/t)
1 264	3.61	7.37	155
2 527	5.84	7.37	155
12 539	25.43	7.37	155

Assumptions

1. Capital costs converted from 1988 to September 1989 U.S. dollars using Chemical Engineering Plant Cost Index.
2. September 1989 foreign exchange rate: $1 U.S. = $1.1828 Canadian (U.S. Federal Reserve Bulletin, January 1990).
3. Electricity Cost: $.047/ kWh.
4. Accuracy range for estimates -30 to +70%.
5. Capacity factor 100%.

Table 18 Overland Pipeline Costs (1989 Canadian $) (Steinberg *et al.*, 1984; Wolsky and Brooks, 1985; Morgan, 1984; Ford, Bacon & Davis, Inc., 1985)

Diameter cm (inches)	Capacity (t/day)	Capital Costs [$1000/(t·km)]	Operating and Maintenance Costs [$/(t·km)]	Offshore Capital Cost Factor	Energy Penalty [kWh/(t·km)]
12.7 (5)	3 118	117.4	.0089		.180
60.9 (24)	50 168	258.9	.0023		.045
76.2 (30)	78 350	306.3	.0018		.036
101.6 (40)	139 113	458.4	.0014		.027
106.7 (42)	153 504	492.8	.0013	1.86	.026

Assumptions

1. Capital costs converted from 1985 to September 1989 U.S. dollars using Chemical Engineering Plant Cost Index.
2. September 1989 foreign exchange rate: $1 U.S. = $1.1828 Canadian (U.S. Federal Reserve Bulletin, January 1990).
3. Accuracy range for estimates -30 to +70%.
4. Electricity cost: $.0457/kWh.
5. Capacity factor 100%.

PART 2

Section 5

Canadian Utilities Simulation Code (CANSIM)

In this section, the technologies described in Part 1 have been incorporated into the Canadian Utilities Simulation Code, known as CANSIM, to evaluate their effectiveness and costs. CANSIM computes emissions and power costs for various scenarios.

The emphasis in this report is on removing CO_2 from existing or planned generating units fired by fossil fuel. Substituting more hydraulic or nuclear power for the fossil fuel is not considered in this analysis, although it is obviously one of the possible reduction methods.

As mentioned in Part 1, the 1988 Conference on the Changing Atmosphere focused attention on CO_2 and the "greenhouse effect" and called for a 20% reduction in CO_2 from 1988 levels by the year 2005. This was set as the target reduction for the simulation runs. This target was not achieved in all simulations but enough reductions were obtained to carry out a representative cost comparison.

5.1 Selection of Technologies

5.1.1 Carbon Dioxide Removal

In Part 1, three CO_2 removal technologies were identified that may be potentially feasible. Two are based on solvent extraction of CO_2 from normal flue gas, and the third uses direct oxygen firing to produce a flue gas containing only steam and CO_2. The solvent extraction process using FS-1L has the lowest capital cost but the sulphur content of the flue gas has to be very low. Even with a flue gas desulphurization (FGD) system, the process would probably not function because of SO_2 poisoning of the solvent. This leaves either the Selexol process or the direct oxygen firing system. There is some doubt about the Selexol process because it requires a very large compressor to compress the flue gas to about 1 520 kPa (15 atmospheres). Since the gas would contain ash and SO_2, it would be abrasive and corrosive and the design of the cleanup system and the compressor would require development. Some of these problems do not arise with the direct oxygen firing system since less flue gas would have to be compressed. Capital and operating costs are similar for both systems. The Selexol process was chosen as a representative cost model for the simulation.

Before disposal of the CO_2, the gas has to be moved to a disposal site. In all cases it has been assumed that the gas will be compressed to about 30 398 kPa (300 atmospheres). The cost model developed in Part 1 is used on all plants to which controls are applied.

5.1.2 Carbon Dioxide Disposal

The disposal of CO_2 poses major technical and environmental problems. The three systems that have been identified as being potentially feasible from an engineering standpoint are deep ocean disposal, forming carbonates from brine aquifers, and injection into oil wells.

Deep ocean disposal is feasible for generating stations located close to the deep ocean, which can be considered an infinite sink for this study. There are concerns, however, about effects on the deep ocean

environment. The second system could apply to sea water and brine aquifers located in Saskatchewan and Alberta. No cost figures were determined for a brine/CO_2 scrubber, but it was felt that for ocean sites, scrubbing would not be significantly cheaper than deep sea disposal, if carbonates are removed from the brine before returning it to the sea.

Straight solution of CO_2 in sea water would require returning the sea water to a point where dissolution would not occur (off the continental shelf). Costs for this would probably be similar to deep sea disposal of dense phase CO_2.

For sites near large brine aquifers, such as power stations in Saskatchewan or Alberta, CO_2 could be disposed of by scrubbing with brine and then removing the carbonates and returning the spent brine to the aquifer via a deep well. Representative costs of this type of system have not been found in the literature, nor has a feasible engineering design been developed.

For this study, it has been assumed that the scrubber would cost about the same as an FGD system, and the cost used in the analysis for the CO_2 scrubber and carbonate sludge removal system was $200 per kW of the generating station's gross electric power. The contact area required for the scrubber may be larger than for a standard FGD system but, on the other hand, the pressure could be higher and this would enhance the solubility. This is within the overall estimate accuracy of the costs in Part 1, which is -30% to +70%.

It was further assumed that the CO_2 would be shipped in liquefied form by pipeline to the scrubber so that compression and shipping costs would be similar to those for deep sea disposal.

5.2 Environmental Concerns

For this report, it has been assumed that certain technologies can be applied to remove CO_2 without severe environmental consequences. There are obvious environmental problems that would have to be overcome, however, before any of these technologies could become a reality. For example, for deep ocean disposal, the CO_2 would in theory remain on the ocean floor, since at 4 000 m it has a density greater than water at the same temperature. But, in fact, the following questions would have to be answered before these technologies could be applied.

- Would these pools of CO_2 be stable? Could upswelling currents entrain the CO_2 causing a sudden release?
- Could the CO_2 in these pools migrate in the deep ocean?
- Could the CO_2 in either pure form or in high concentrations in water harm deep ocean life forms?
- What international framework would be required to establish legal responsibility for the waste CO_2?
- What are the insurance liability implications?

Similar problems would arise with establishing CO_2 pipelines over land. Although natural gas has been transported by pipeline for many years, problems could arise with the very large diameter pipes (1 m) that would be required to carry CO_2 in its dense phase. Could solid CO_2 be formed? Could a two-phase mixture be formed? The danger here would be slugs of liquid or solids travelling at high speed in the pipe and hitting obstructions such as elbows.

In this study, only construction costs have been considered, to obtain an approximate cost of CO_2 controls. If more studies are needed, environmental concerns would have to be evaluated in detail.

5.3 *The CANSIM Code*

The analysis was carried out using the computer code CANSIM. CANSIM is a province-wide, electrical utility simulation code that estimates station loading and emissions on a yearly basis, based on a given annual electrical demand. The code is designed to estimate utility emissions to air and the cost of reducing these emissions. The data used is basically a list of all generator units available in the province with their capabilities and efficiencies.

An estimate for the power generation requirement for each year is obtained from the provincial utilities. The stations available to generate the required power are then loaded onto the system, generally in the order of lowest power cost, until the required load is obtained. Based on their loading and the assumed emission controls on the unit, the station's emissions are computed. Detailed cost models of emissions abatement technologies for fossil fuel generated power stations are included in the model, to estimate the cost of emission reductions. A full description of CANSIM is provided in Appendix A.

5.4 *Incorporation of Cost Models Into CANSIM*

The CANSIM code was modified to incorporate the Selexol solvent extraction for the CO_2 removal system. CANSIM computes the CO_2 emissions based on unit efficiency, power output, fuel carbon content, and heat value. Assuming that the solvent extraction removes 97% of the CO_2 generated, the amount removed determines the capital cost of the extraction unit.

The power to drive the system is accounted for by subtracting a power penalty from the unit output. That means that at full load, the unit will burn the full fuel load but would only produce the nominal output minus the power penalty.

To determine pipeline costs, a single pipeline is shared by groups of stations and the costs split between them equally. The diameter of the pipe is established by adding the total CO_2 captured by all the plants in the group and assuming it is in the dense phase and travels in the pipe at 1.0 m/s (3 ft/s). The cost of pipeline is then estimated based on published data (Morgan, 1984). The power costs of pumping the liquid are based on an overall efficiency of 60%.

The velocity of 1.0 m/s was established by computing the annual costs of various sizes of pipes carrying a fixed quantity of high pressure CO_2 in their first year of operation. The annual costs consisted of 14% interest on capital, 2% of capital as fixed O and M costs, and power costs of 4 ¢/kWh. For a range of CO_2 quantities of interest to the study, the minimum first year annual costs were achieved with a liquid velocity in the range of 1.0 to 1.5 m/s. According to Shell Canada, the figure used for CO_2 pumping in Canada is 1.0 m/s which was used as a basis for the cost model.

The CO_2 removal and disposal systems require a significant amount of power – about 25% or more of the plant output depending on its location relative to the disposal point. Most of the power is consumed in compressing either air for oxygen liquefaction or flue gas for the Selexol process and then CO_2 for injection

into the pipeline. The power required for pumping along the line is minimal compared to these other power requirements.

The incremental cost of the power consumed by the CO_2 systems is accounted for by penalizing the station output, but the capital costs are not accounted for unless the reserve margins remain the same in the utility. The reserve margin is not a smooth curve, but it tends to "sawtooth" about a value of approximately 20%. The size of the variation is a function of the growth rate, and unit additions and retirements. For a change in demand as significant as would be caused by CO_2 emission controls, the reserve margin changes considerably. Stations have to be added to keep the reserve margin nearly constant, but it is not possible to match the uncontrolled margin exactly.

An attempt was made to do this, but even without CO_2 controls, the best information available from the utilities does not produce a flat reserve margin up to the year 2010. There is a tendency in all cases for it to fall with time as planning becomes less concrete. When the CO_2 emission simulations were run, new stations were added to maintain the reserve margin at least above the minimum value predicted over the simulation period without CO_2 controls.

When the power costs for the various simulations are compared, the effect of the reserve margin on this cost should also be considered.

5.5 *Projections Using CANSIM*

The preceding cost models were incorporated into CANSIM. Studies have recently been done for Environment Canada on the costs associated with SO_2 and NO_x reductions for most of the provincial electrical utilities. The basic data from those simulations have been used as a starting point in this study. Where feasible, CO_2 controls have been applied in each province with the objective of reducing the total power plant emissions to below the 1988 level.

5.5.1 *Provinces Not Simulated*

Prince Edward Island, Quebec, Manitoba, and British Columbia were not included in the simulations as they do not have long-term CO_2 emissions. As Prince Edward Island imports most of its power from New Brunswick, controlling the latter province is sufficient.

Quebec generates most of its power from hydraulic stations. There is one nuclear plant and one oil-burning plant. The oil-burning plant, located in Tracy, has acted as a peaking unit and has been used more extensively only in recent years because of low water levels. It was assumed that, if CO_2 controls were imposed, the station would not be used and it would be replaced by more hydraulic power.

In Manitoba, 90% of the power is from hydraulic units. There are two fossil-fueled plants at Brandon and Selkirk, but these are to be retired in the year 2000 when the new hydraulic unit at Conawapa comes on line.

British Columbia has all hydraulic generation except for Burrard, which is gas-fired and represents a small fraction of the total utility.

5.5.2 *Provinces Simulated*

Newfoundland. It was assumed that the only station subjected to controls in Newfoundland was Holyrood, which has three 150-MW units. Because this station is the major CO_2 emitter in the power

generation sector, the overall CO_2 levels are reduced well below the target value of 20% when all three units were controlled (as shown in Figure 9a). If fewer controls are targeted, then the corresponding power costs shown in Figure 9b would be lower.

The reserve margin shown in Figure 9c shows a continuous decline, even for the no-control case. It is not clear, therefore, that the capital charges for the additional power required to drive the system are adequately covered. A new plant is added around the year 2008 to maintain a reserve above the no-control case minimum, but the simulation may not be very realistic because of the very low predicted margin for the no-control case.

Nova Scotia. Nova Scotia burns mostly local coal plus some imported oil. Future plans project new stations will be coal-burning. The CO_2 would be disposed of by deep ocean injection. A depth of 3000 m is found approximately 350 km offshore.

It was assumed that the existing Lingan stations, plus new fossil-fueled stations, would be subjected to CO_2 controls. The estimated CO_2 emissions and the expected power costs are shown in Figures 10a and 10b.

Additional electric power is required to power the CO_2 removal systems. It is assumed that this is supplied by building extra fossil plants to make up the shortfall, so that the reserve margin is maintained at the minimum level it is projected to have without CO_2 controls. The resulting reserve margin is shown in Figure 10c.

To maintain the CO_2 emissions at the 1988 levels, the power cost (in constant 1988 dollars) would increase from about 6.8 to 8.5 ¢/kWh. The capital costs on a per station basis are about $71 million for CO_2 removal and compression and $65 million for piping it out to sea. About 25% of the station's output is required for the CO_2 removal and disposal systems.

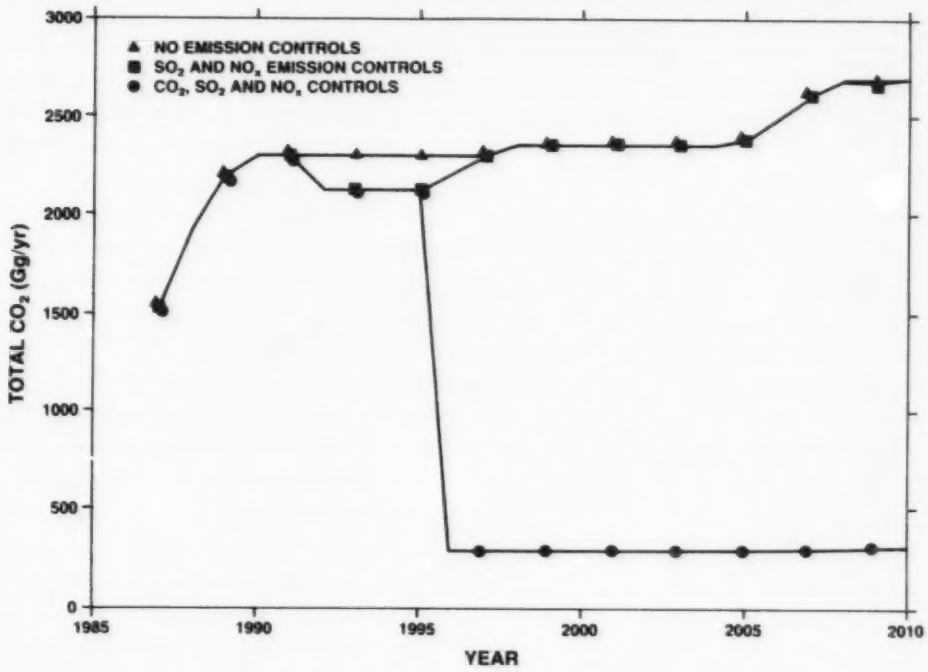
New Brunswick. In New Brunswick, the new generating plant is currently projected to be coal-fired stations burning imported coal. It is assumed that CO_2 controls were applied to these new 400-MW stations and to the 1000-MW station at Coleson Cove. This report does not consider the fact that CO_2 controls may change the choice of generation type, but this is obviously a possibility. The CO_2 would be disposed of by injection to the deep ocean. On average, it is expected that the pipeline would run approximately 100 km over land and 350 km under the sea to reach depths of over 3 000 m.

Three simulation cases were run with the CANSIM model: the first with no controls, the second with acid gas controls, and the third with acid gas, as well as CO_2 controls.

The CO_2 emissions are shown in Figure 11a and the power costs are shown in Figure 11b. Again, additional generating capacity is required to power the emission controls, and this is assumed to be supplied by additional coal-burning fossil plants with CO_2 controls such that the reserve margin is at least up to the minimum currently projected. The reserve margins for the three cases are shown in Figure 11c.

Emissions were reduced from 6 000 kt/yr to approximately 4 000 kt/yr by the year 2010, which was more than the recommended 20% reduction. The power costs would increase from about 4.5 to 6 ¢/kWh (30% increase) for this reduction. Fewer CO_2 controls would result in a slightly smaller cost increase.

a. Carbon Dioxide Emissions



b. Power Costs (¢/kWh)

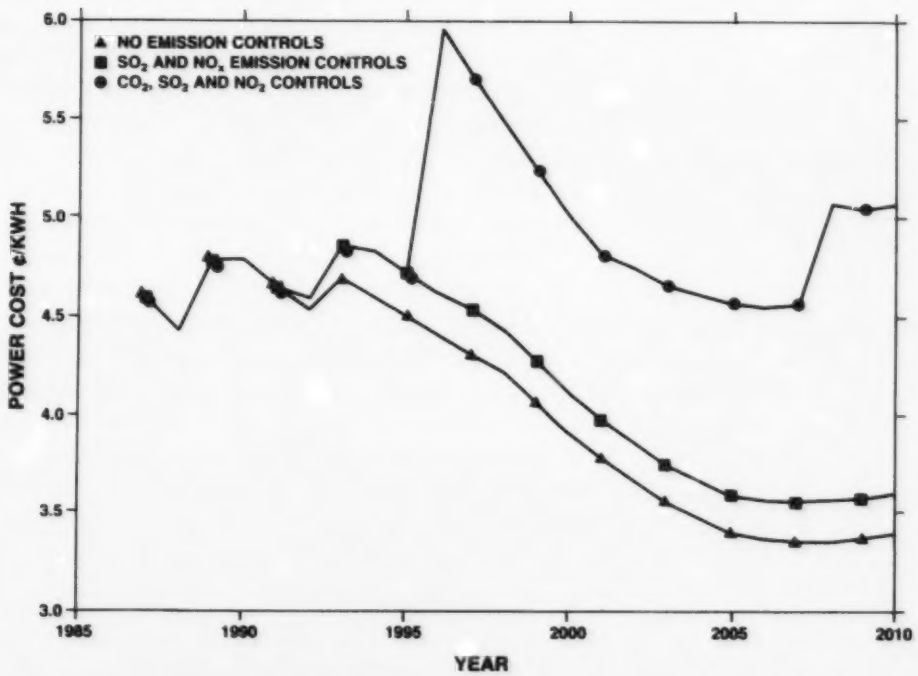


Figure 9 CANSIM Results - Newfoundland

c. Reserve Margin

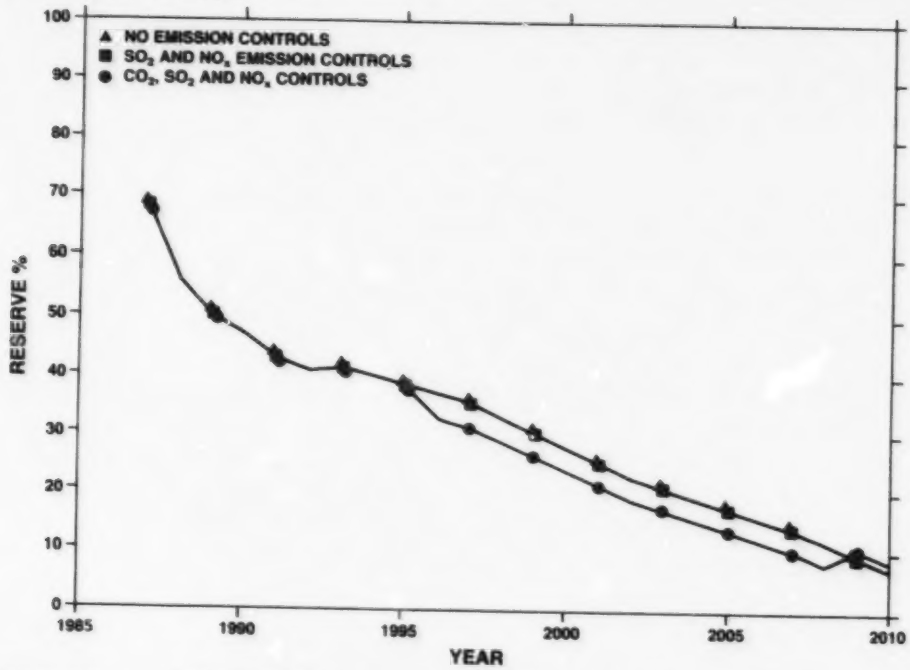


Figure 9 CANSIM Results - Newfoundland (Cont.)

a. Carbon Dioxide Emissions

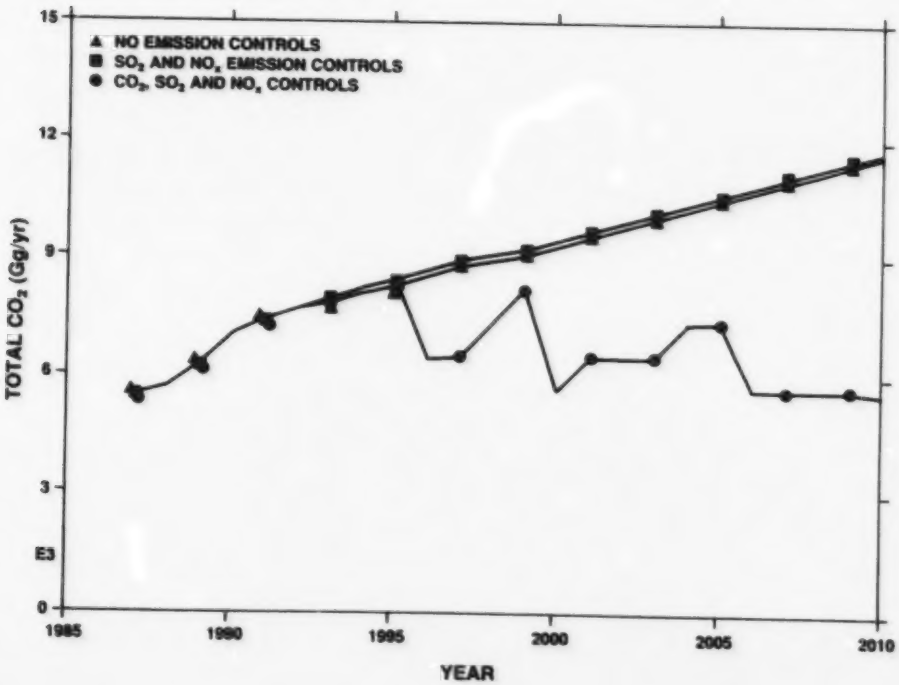
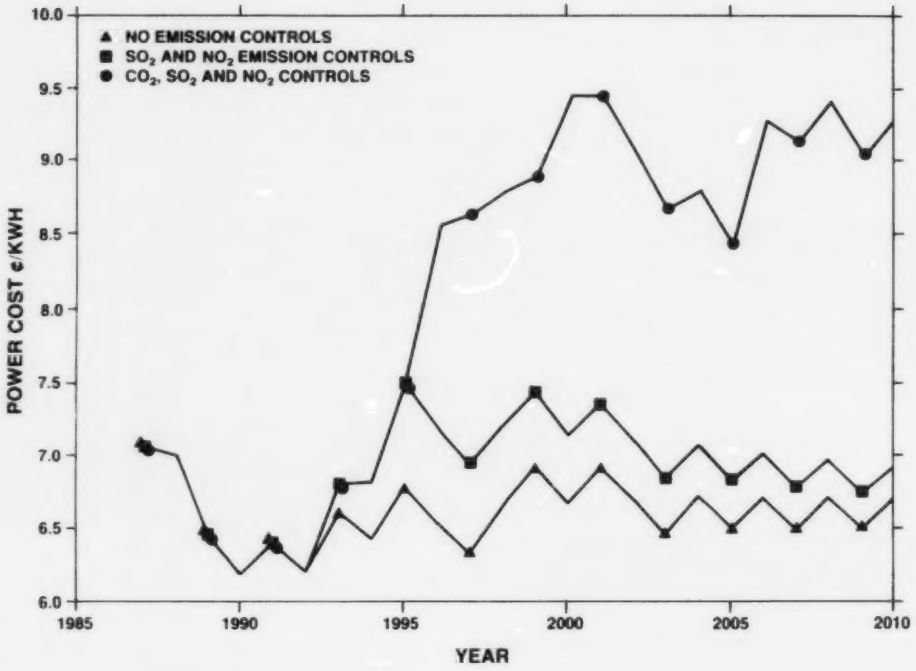


Figure 10 CANSIM Results - Nova Scotia

b. Power Costs (¢/kWh)



c. Reserve Margin

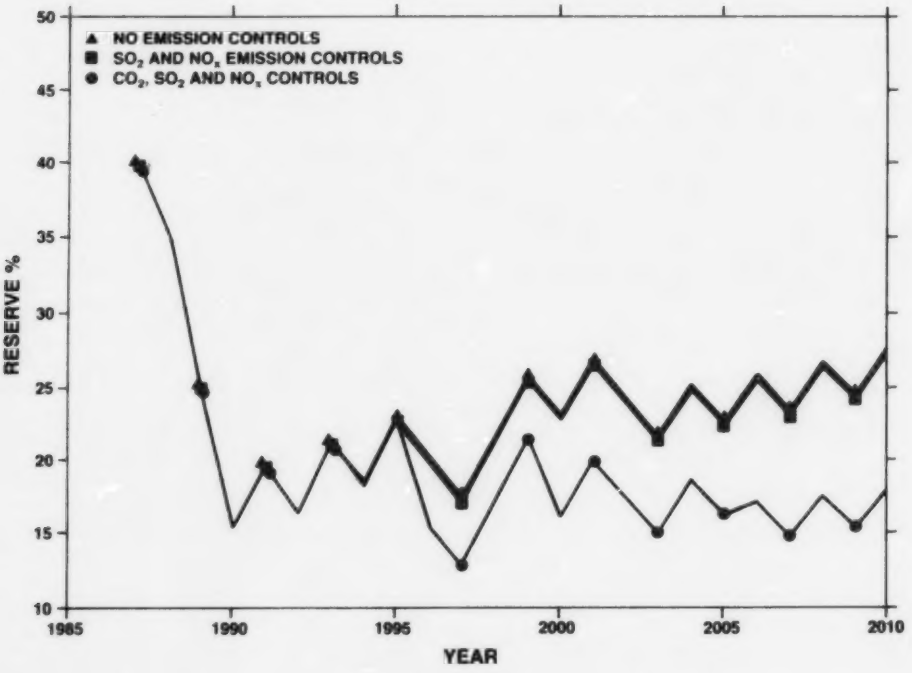
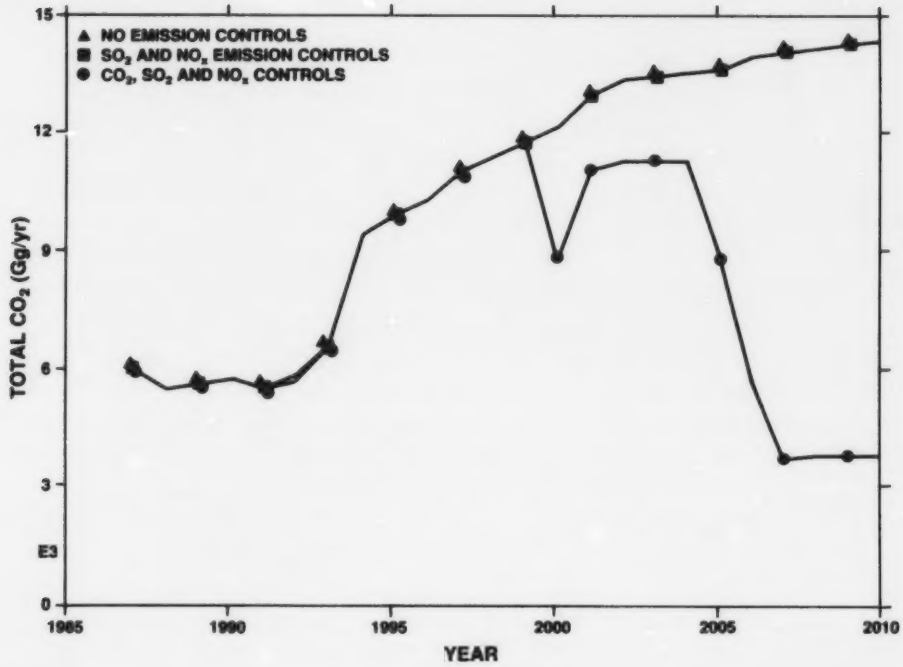


Figure 10 CANSIM Results - Nova Scotia (Cont.)

a. Carbon Dioxide Emissions



b. Power Costs (¢/kWh)

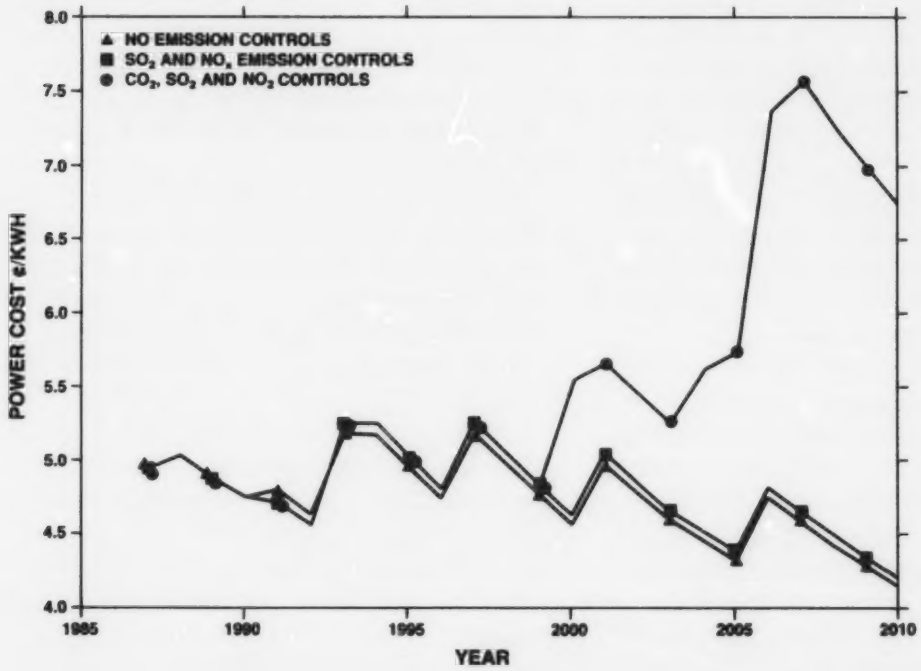


Figure 11 CANSIM Results - New Brunswick

c. Reserve Margin

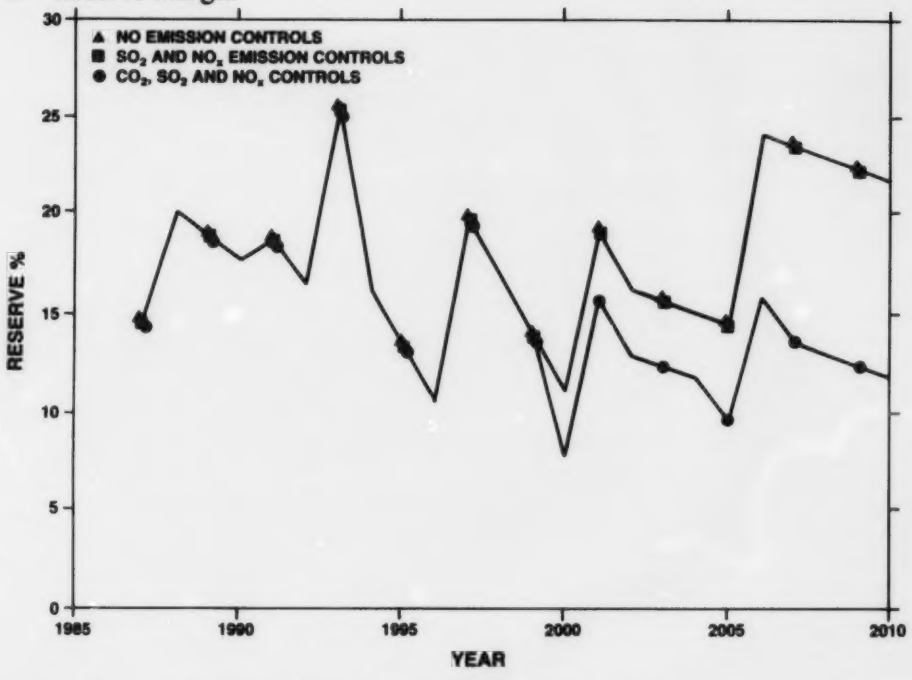


Figure 11 CANSIM Results - New Brunswick (Cont.)

The capital costs of the system for a 400-MW station are about $209 million (in 1988 Canadian dollars) for removal and compression and $52 million for pipelines. The total power penalty is 102 MW, about 25% of the station's normal output.

Ontario. Approximately a third of Ontario's electricity is now generated by fossil-fuel plants. If CO_2 controls became mandatory, the fossil-fuel plants could be replaced with nuclear plants or power could be imported from other provinces. These options are not considered in this analysis. Based on Ontario Hydro's estimates, nuclear plants would be cheaper than fossil-fuel plants with acid gas controls, so that a simulation replacing the new fossil-fuel plants with nuclear plants would show lower power costs than currently projected. Due to the lead time required for approval and construction of a nuclear plant, however, this option was not considered feasible within the time frame of this study.

It is assumed that CO_2 controls are applied to Lambton and the new Integrated Coal Gasification Combined Cycle (IGCC) plants. Disposal would be by pipeline to the ocean. The shortest distance to a point in the Atlantic, via the United States, is approximately 1 600 km, and this distance has been assumed in the study. Should the pipeline be entirely in Canadian territory, it would have to be about double in length, i.e., 3 000 km.

Two runs were done, the first with no CO_2 controls using the Ontario Hydro Plan #15 (Ontario Hydro, 1989). In this run, new fossil-fuel plants, which may start operation as simple, combined-cycle plants, are assumed to be coal-burning rather than gas-fired. The coal gasifier is therefore in operation. During this run, it is assumed that

FGDs are fitted to Lambton and half of Nanticoke for SO_2 control.

The second run assumes CO_2 controls on Lambton and the IGCCs. Carbon dioxide is removed by the Selexol process, compressed, and sent by pipeline to the ocean. The projected CO_2 emissions are given in Figure 12a, and the estimated power costs in Figure 12b. It is assumed that no additional capacity would be added to offset the power consumed by the control equipment, so the reserve margin is less for the CO_2 control case, as shown in Figure 12c. The increase in power cost does not appear large because only a few stations are controlled. In the year 2010, however, the normalized incremental power cost for Lambton increases from 6.5 to 9.1 ¢/kWh.

The total capital expenditure per unit at Lambton would be $488 million. The power penalty to the unit is 137 MW out of a nominal 525 MW, about 26% of its output. For the 1 680-MW IGCC plant assumed to come into service in the year 2008, the cost of CO_2 controls doubles the estimated capital costs for the plant from $4.5 billion to $9.3 billion (2008) and reduces the output by 25%.

Saskatchewan. In Saskatchewan, approximately 60% of the power is generated from local lignite. Two new stations are planned at Shand and three more lignite-fired units after the year 2000.

It was estimated that the best location for the disposal site was within 200 km of the power stations. It was assumed that the CO_2 would be removed from the flue gas by solvent extraction and compressed and transported in liquid form to the disposal location. Disposal would involve contacting the flue gas with brines from the Elk Point Basin brine aquifer and forming a precipitate of carbonate that could be removed by filtration. The spent brine would be returned to ground by a deep well. This scheme has not yet been tested, although in theory it appears feasible. Since the conceptual design of a suitable scrubber was beyond the scope of this study, it was estimated that the capital cost would be similar to an FGD system (approximately $200/kW).

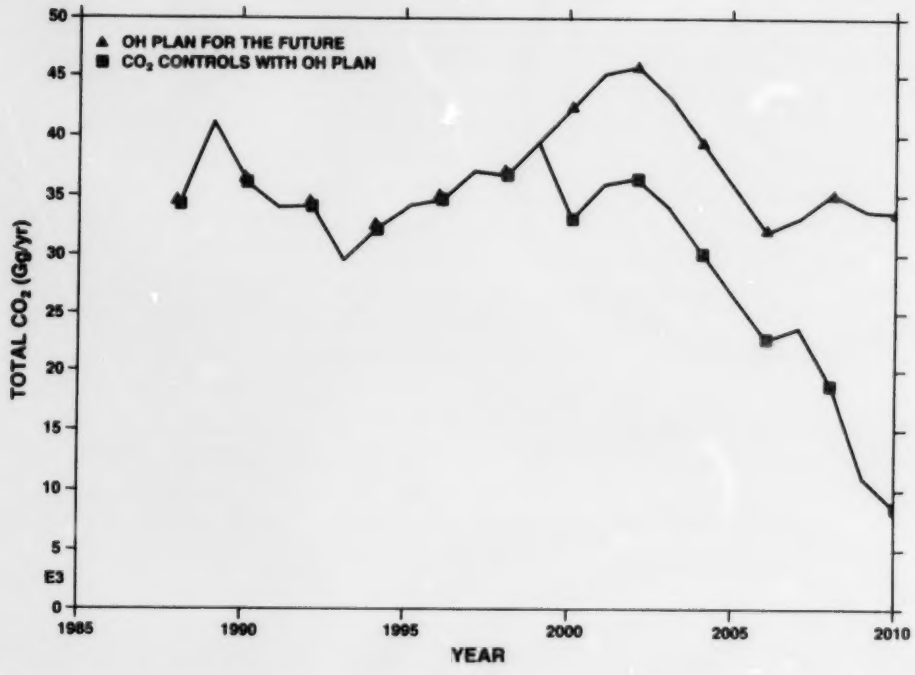
The suggested control scheme would reduce the CO_2 emissions from approximately 11 000 to 8 000 kt by the year 2010, as shown in Figure 13a. Power costs would increase by about 50%, as shown in Figure 13b. To maintain the reserve margin at a level similar to the original plan, an additional 300-MW lignite unit was added to the system, as shown in Figure 13c.

Alberta. In Alberta, over 80% of the electric power is generated by coal-burning units. Without controls, the CO_2 emissions will increase from the current value of 33 000 kt/yr to 60 000 kt by the year 2010. To reduce the emissions to 75% of the 1988 values, CO_2 controls were assumed to be applied to power plants at Sheerness, Genesee, and all new coal-fired units. The resulting emissions are shown in Figure 14a. The cost of power is projected to increase from about 4.5 to 7.3 ¢/kWh, as shown in Figure 14b.

The controls are assumed to be the same as in Saskatchewan. The source of brine is assumed to be 300 km from the power plants. Some of the CO_2 could be used for enhanced oil recovery (EOR), but the overall costs would not be very different since it would represent a small fraction of the total (maybe 300 to 600 MW equivalent).

The solvent extraction and compression costs would be the same. The pipeline would be longer for EOR but the brine

a. Carbon Dioxide Emissions



b. Power Costs (¢/kWh)

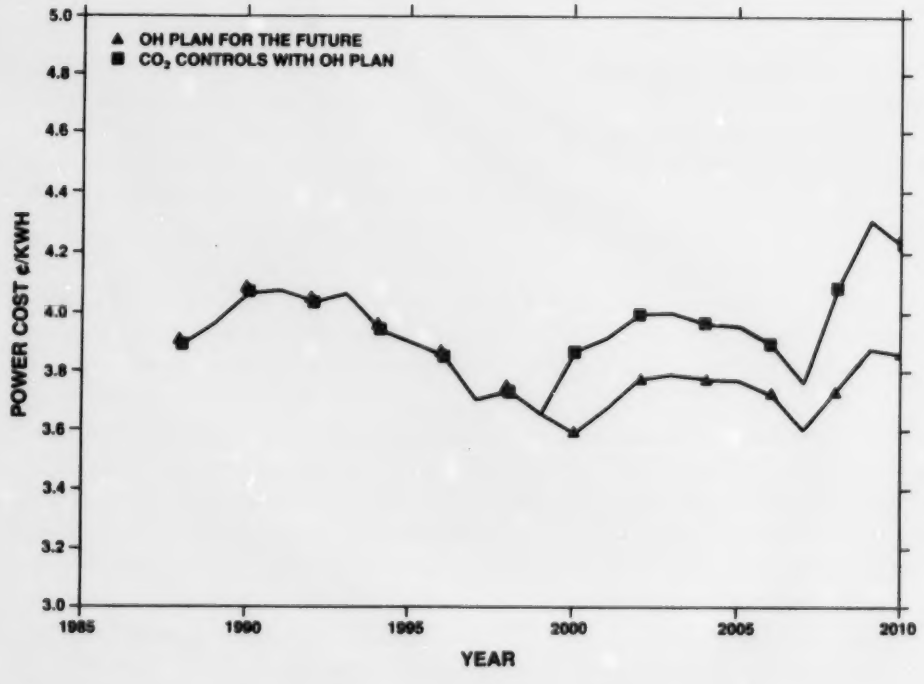


Figure 12 CANSIM Results - Ontario

c. Reserve Margin

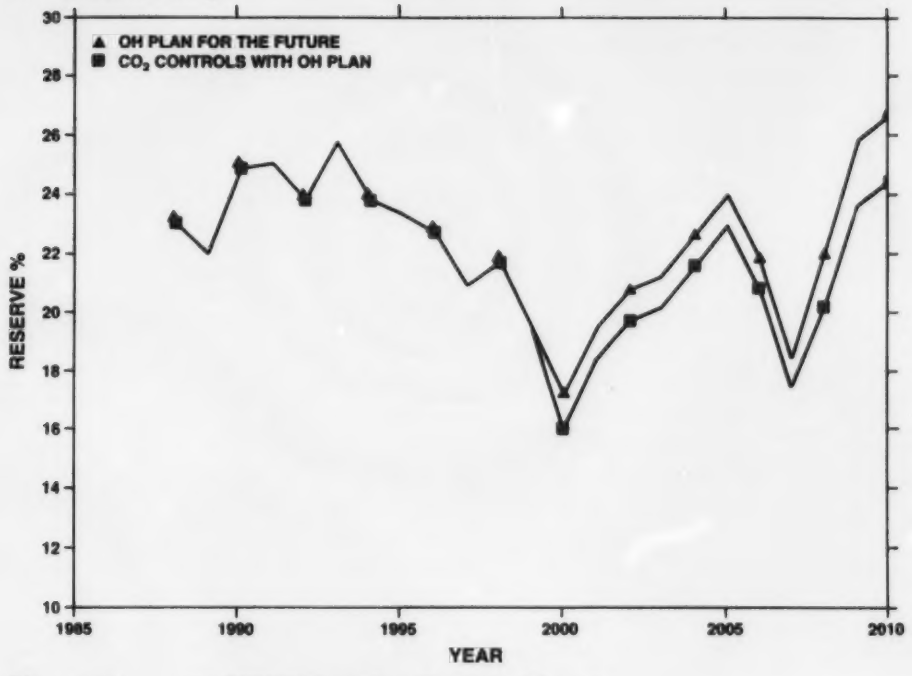


Figure 12 CANSIM Results - Ontario (Cont.)

a. Carbon Dioxide Emissions

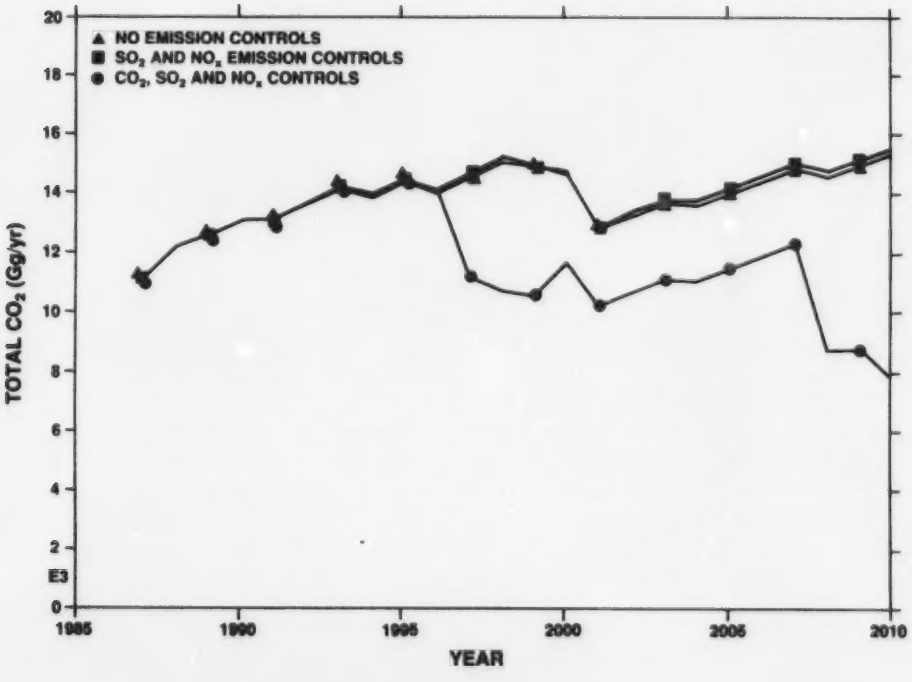
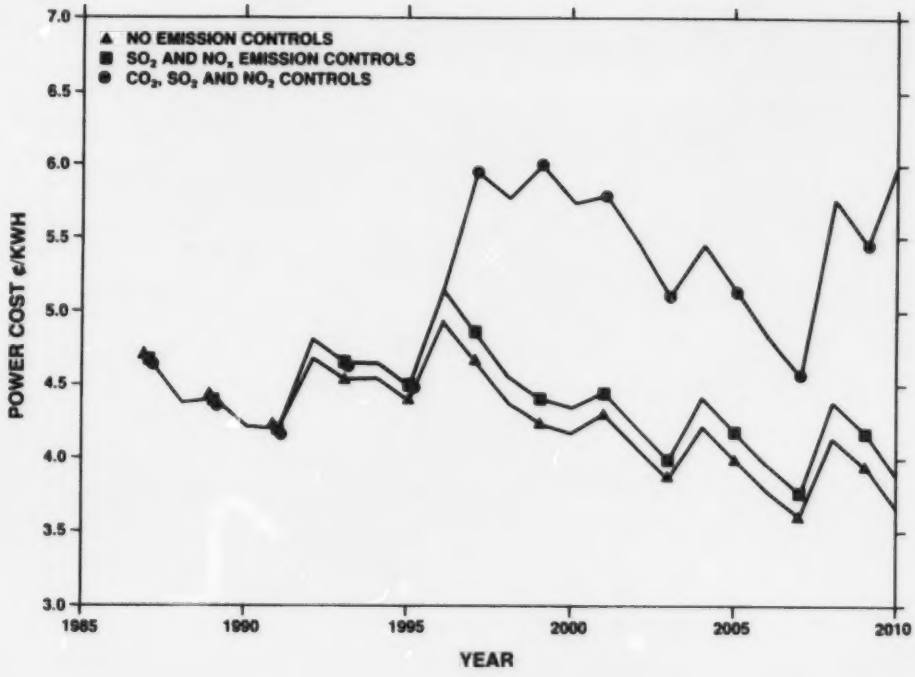


Figure 13 CANSIM Results - Saskatchewan

b. Power Costs (¢/kWh)



c. Reserve Margin

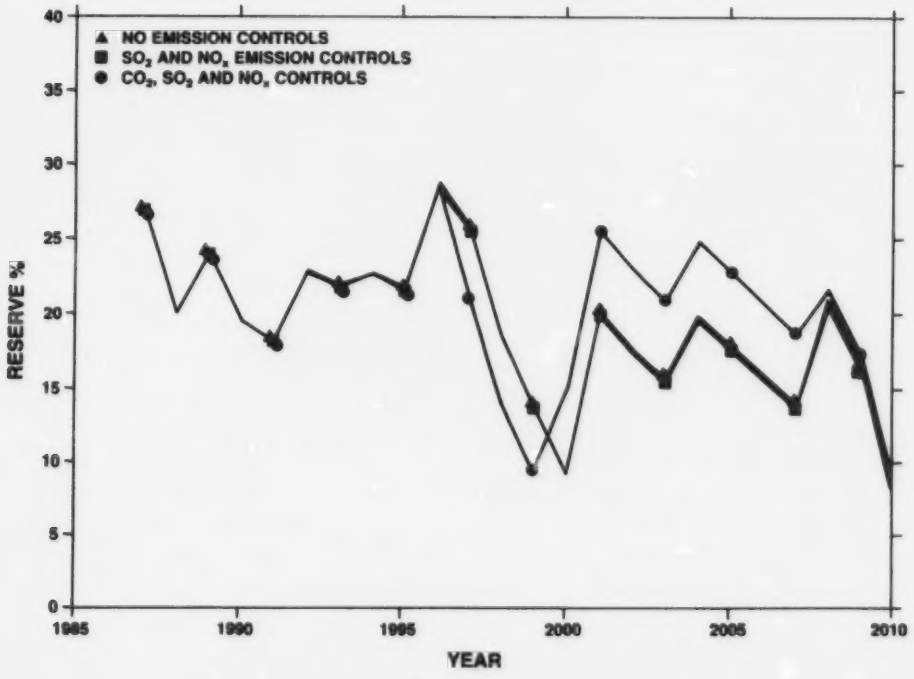
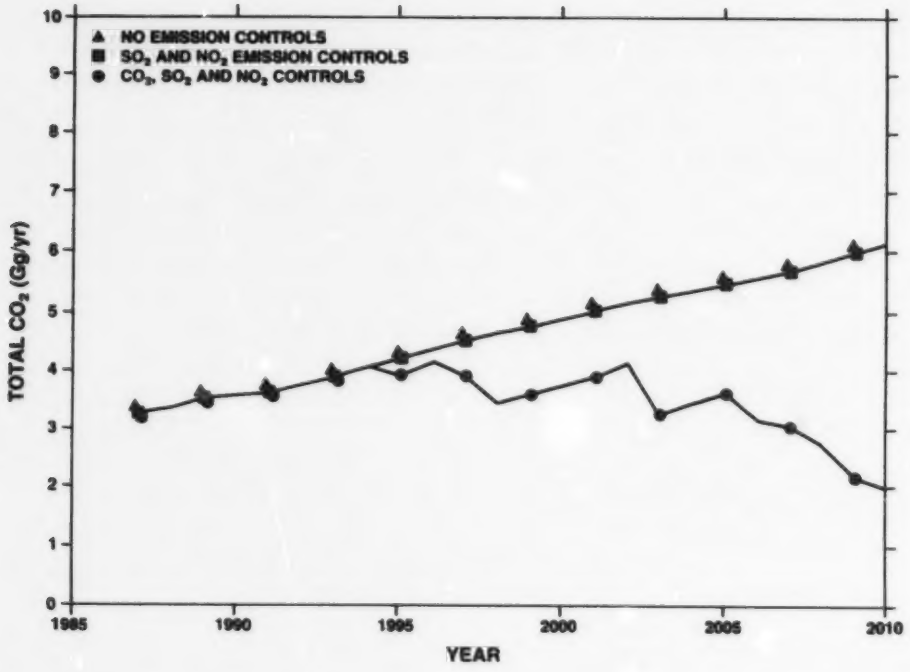


Figure 13 CANSIM Results - Saskatchewan (Cont.)

a. Carbon Dioxide Emissions



b. Power Costs (¢/kWh)

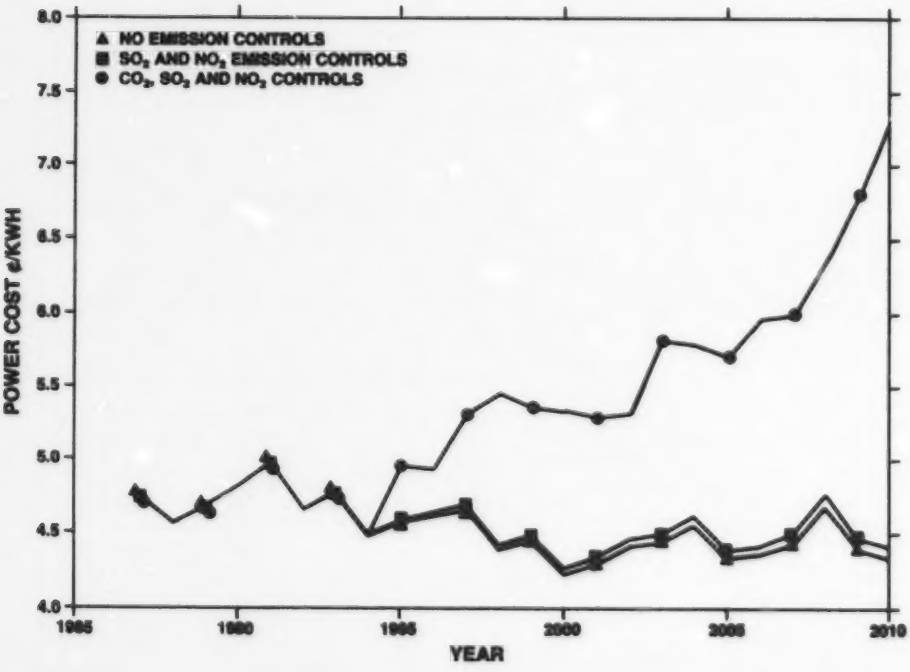


Figure 14 CANSIM Results - Alberta

scrubber would not be included. There could be some revenue generated from the sale of CO_2 to the oil companies but, compared to the total of over 8000 MW of fossil power with CO_2 by the year 2010, the revenue from EOR sales would be within the error bounds of the current cost estimates.

Four additional 370-MW units are added to the grid to maintain the reserve margin in a reasonable range. This is not quite sufficient to maintain it at the original planned level, but it is representative. The trend is shown in Figure 14c.

c. Reserve Margin

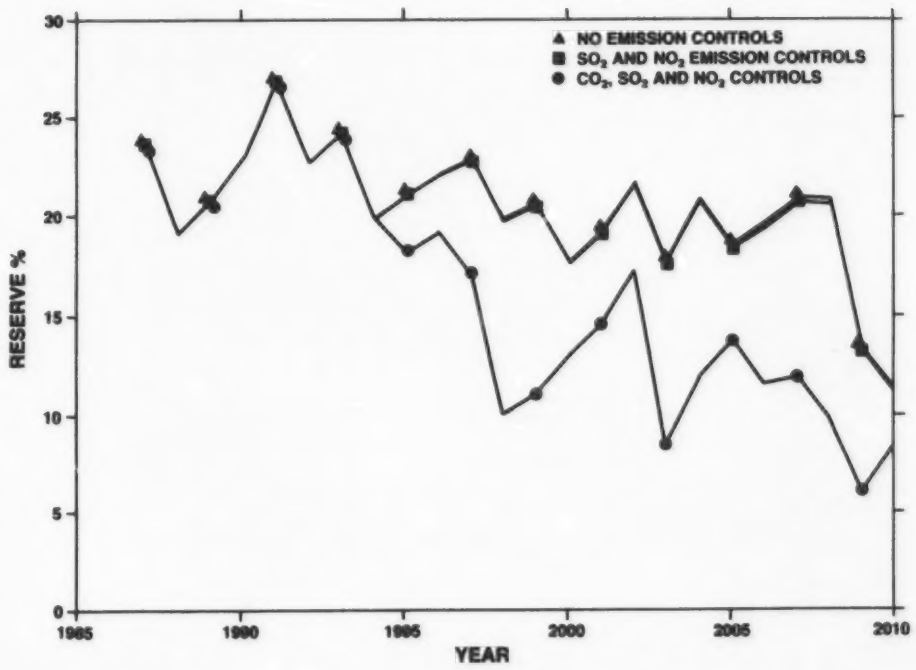


Figure 14 CANSIM Results - Alberta (Cont.)

Section 6

Conclusions

If the problems associated with deep ocean disposal of CO_2 are resolved, using CO_2 controls on fossil-fuel power plants could reduce CO_2 emissions by 20% from current values as recommended by the 1988 Conference on the Changing Atmosphere. The estimated Canadian emissions, with and without controls, are shown in Figure 15a. However, the cost of these controls would be considerable.

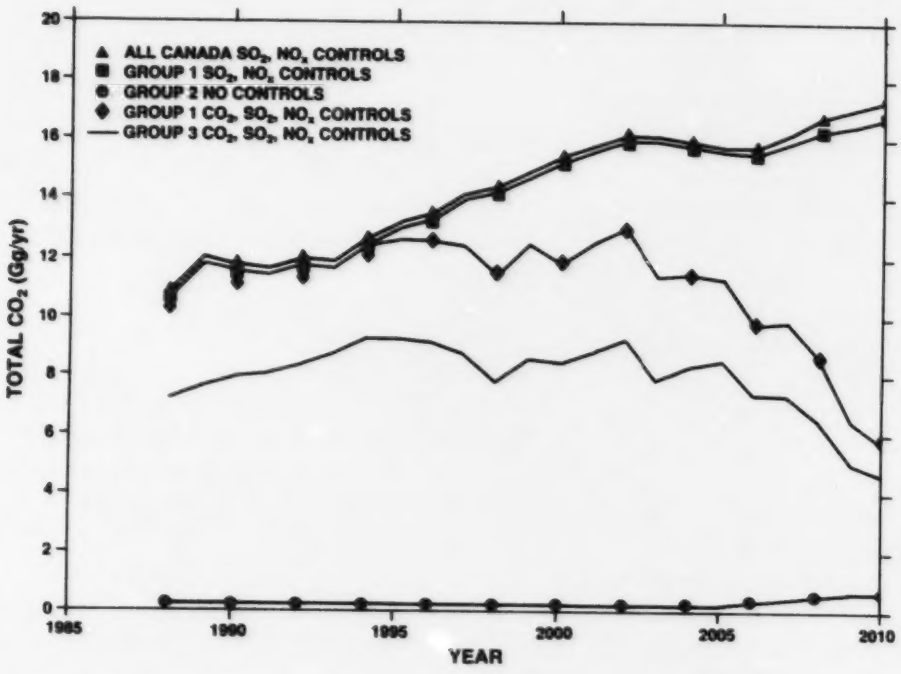
It has been assumed in this report that plans for power generation in the future would remain similar to the current ones and some existing and new fossil-fuel plants would be subjected to CO_2 controls. No wholesale switch to nuclear generation has been assumed. On this basis, the overall annual costs are shown in Figure 15b. The utilities are grouped to represent provinces with mainly hydraulic or fossil-fuel generation. Group 1 consists of Newfoundland, Nova Scotia, New Brunswick, Ontario, Saskatchewan, and Alberta. Group 2 consists of Quebec, Manitoba, and British Columbia. Group 3 is Group 1 without Ontario. This group is shown separately because Ontario projections include the nuclear option, which in itself will reduce CO_2 emissions. All reduction in Group 3 is due to controls. It is evident that fossil-fuel generation, even without controls, is more expensive than hydraulic. The CO_2 controls would increase power costs by at least 50% for the provinces with mainly fossil-fuel generation.

The capital cost of a new fossil-fuel plant with CO_2 controls would approximately double. The overall efficiency would decrease from 36% to about 27%.

The following are recommendations for further work:

- generate comparable power cost figures for alternate generation technologies;
- define more exactly the capacity limitations for enhanced oil recovery, and the disposal of CO_2 in depleted oil wells;
- carry out additional work to show feasibility of CO_2 capture by brine aquifers; and,
- if more accurate power costs are required, conduct a more extensive study to determine capital and installation costs of very large compressors.

a. Canadian Carbon Dioxide Emissions



b. Power Costs in Groups

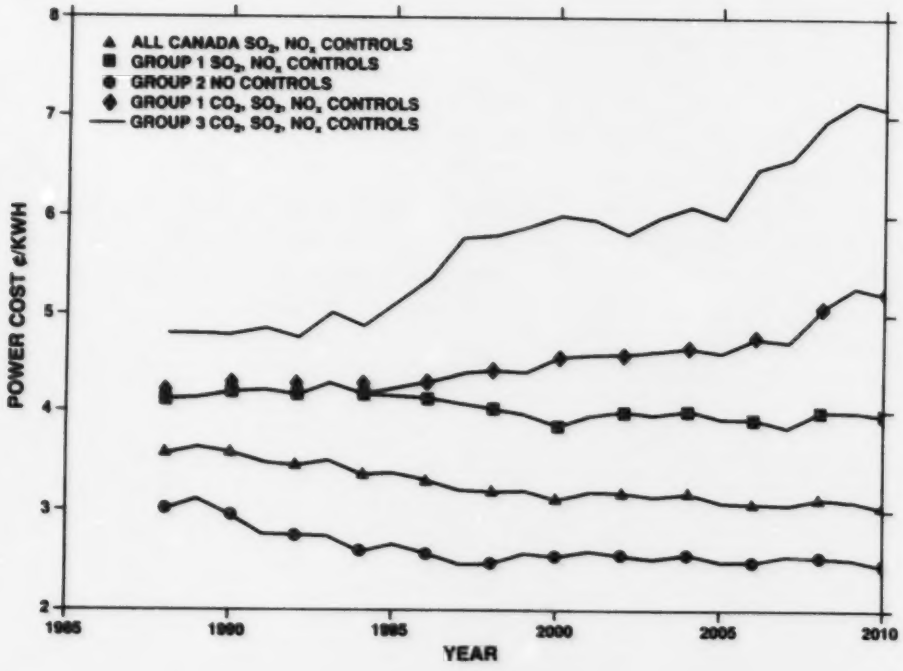


Figure 15 CANSIM Results - All of Canada (except PEI)

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Appendix A

Description of the CANSIM Model

Several options are available to industries required to moderate their output of air-polluting substances. These options range from closing down the offending operation to substituting a process that does not harm the environment.

The electricity-generating industry cannot usually opt to close down an offending station, unless it has a readily available substitute energy source. In terms of acid rain, replacing fuel combustion-derived energy with either hydraulically driven generators or nuclear-powered units would be positive. In most Canadian provinces, however, the reserve of unexploited hydraulic resources is either too small or too far away from the point of ultimate use to be economically attractive for large blocks of new power. Nuclear plants are expensive in terms of initial capital requirements and politically unpopular in some provinces.

At current electricity demand growth rates of about 3.9%, the national total power output will rise by 50% in 10 years and 100% in 18 years. Thus there is continuous pressure on the utilities to extend and enlarge their generating capacity. Existing coal-, oil- and gas-fired boilers will therefore continue to drive electricity generators, and new units will be added to cope with perpetually increasing power demand. This Appendix describes the latest version of the Canadian Utilities Simulation Code (CANSIM) that was used for the emission study of this report. The code generally attempts to obtain an approximate cost for power generation in future years. The cost of acid gas emission reduction is added to this basic cost. These costs are derived from relatively detailed cost models. In order to obtain emission estimates, existing generating capacity and future demand and supply plans are included in the simulation.

Scope of Model. The public is increasingly aware that air-polluting emissions must be curtailed, in spite of everyone's desire for a rising standard of living and the consequent increases in industrial production. Given the use of fossil fuels to cater to part of the present demand for both electrical energy and future energy growth, the utilities must determine how to achieve the required reductions in polluting emissions, and at what cost. The realistic options include:

a) substitution of another source of power;

b) substitution of a naturally occurring, less polluting fossil fuel;

c) sulphur removal from available high sulphur fuel, through use of physical or chemical processes before combustion; or

d) removal of acid gas from combustion gases by chemical transformation to other compounds, either useful or readily disposable as wastes, e.g., sulphuric acid, ammonium sulphate (fertilizer), calcium sulphate (gypsum).

Thus the choice of any particular method of reducing emissions from a single boiler depends on many, sometimes conflicting, factors, including degree of removal required, physical possibility of retrofitting equipment, effects on boiler design

performance, reliability and availability, the availability of alternative fuels and their suitability for use in an existing unit originally designed for another fuel, and frequency of use of boiler on load, etc.

For any utility, but particularly for those operating a system powered by hydraulic, nuclear, and fossil fuels simultaneously, the choice of any particular method becomes extremely complicated. Varying capital construction costs, operating costs, and life expectancies of the different units are further complications. To resolve the difficulties of analyzing electric power systems for the implications of emission control, equations have been developed relating overall systems and individual units for yearly energy demand, least-cost electric power production, capability of different reduction technologies, and their capital, operating, and fuel costs, and system generation capacity, among others.

These functions have been incorporated into the IPB computer model for a complete utility, known as CANSIM – Canadian Simulation of Utility Operations. The code is designed to estimate utility emissions and the cost of reducing these emissions.

Details of Cost Models

Capital Cost Model. The capital cost model has been developed based on advice given by Clarkson Gordon. The method of treating both base year capital and new capital is similar to the accounting methods used by the utilities.

The basic financial data used to initiate the capital cost model are contained in the utilities' annual reports. The cost of capital borrowed (as stated in the annual report) is made up of three components: interest, depreciation, and taxes.

It is assumed that these costs remain constant except that taxes increase with inflation. This assumption means that the existing capital costs will actually decrease in real terms with time. Then, as new capital assets are added to the base year assets, additional capital costs are incurred. One of two methods may be used to compute the cost of this new capital:

1) a mortgage (similar to a sinking fund);

2) straight line depreciation.

Straight line depreciation is the method most commonly applied by the utilities. The mortgage method produces equal payments over the life of the plant, whereas straight line depreciation produces higher annual costs initially, but the net costs are lower. It is assumed that the new capital is financed in the year the plant goes into operation.

Capital = size of plant × (cost of plant/kW)

The cost per kilowatt is a function of plant type and varies for each province. This forms part of the input to the model. It does not include the interest during construction or additional capital costs, such as transmission and head office. The interest during construction is computed assuming that costs are distributed equally over the period of construction for each generation type. This interest cost is added to the total capital cost of the plant. The capital cost of additional transmission and other associated assets is added to the capital base on the basis of an average cost per kilowatt for the utility. This cost is derived from the ratio of non-generation assets to generation-based assets as given in the annual report. It is assumed that this ratio remains constant during the simulation period. The capital cost of each type of generation varies from province to province. For coal in particular,

in some provinces the capital includes the coal mine capital and in others it does not. The fuel cost used should reflect the fact that the mine is part of the generating plant if this is the case.

The total capital cost is inflated at the specified inflation rate from the base year up to the on-line date of the plant before being annualized. The annual cost of the new capital is computed on the basis of equal instalments (mortgage) or straight line depreciation. The total payback period is assumed to be the life of the plant.

Unit Dispatch Model. Unit capacity factors are computed so that the total power generated meets the total yearly demand, as described by a load-duration curve. This curve is simulated by dividing it into a number of vertical sections. The units are ordered in either the lowest fuel cost or lowest emission and are used to fill each vertical section in turn. The plants are first loaded up to their minimum specified capacity factor and then they are reloaded to their maximum specified capacity factors until the total generation of that segment of the load duration curve is met.

Generation Planning. The option exists in the code for new units to be put on line at a date that will allow a preselected reserve margin to be maintained. This ensures that runs using different growth rates can be compared on an equal basis. Stations that are planned in the future are added to the unit data file in the order they would be built, with the on-line date left blank. The code will then automatically put these units on line as required to maintain the reserve. If the on-line date is on the file, the unit will be put on line on that date. All capital costs occur from the on-line date, and no pre-commissioning costs are added to the generation costs before that time.

Emission Control Equipment

Airflow. The airflow in the flue gas is computed as a function of station size, station efficiency, fuel heat value, and moisture and ash content. The moisture content is estimated from the following:

Heat Value (Btu/lb)	Moisture Content
Greater than 12 000	10%
Between 12 000 and 7 500	25%
Less than 7 500	35%

The total air flow is one of the parameters used to compute the emission control costs.

Sulphur Dioxide Controls. The SO_2 emissions are computed based on the fuel sulphur content, fuel heat value, and plant efficiency. An allowance is made for sulphur retained in the ash. The following SO_2 emission reduction technologies are currently assessed in CANSIM:

1. physical coal cleaning;
2. sorbent injection into the boiler;
3. dry scrubbing (spray drier);
4. wet scrubbing (wet FGD).

The cost and performance of these technologies are based on other more detailed simulation codes, such as the TVA Shawnee FGD model. Costs are derived based on airflow, SO_2 removed, and type of sorbent.

Nitrogen Oxide Controls. The NO_x emissions are a function of the boiler type given in the input data. If the code-derived values are not representative, they can be overridden in the input.

Three methods of reducing NO_x are simulated in the model:

1) low NO_x burners;

2) urea injection; and

3) selective catalytic reduction (SCR).

The cost and performance of these systems are based on the latest published data. In particular, the published SCR catalyst costs vary considerably.

Particulate Controls. Particulate emissions are computed based on the fuel ash content, fuel heat value, and plant efficiency. It is assumed that all ash goes to the stack and is removed by an electrostatic precipitator. Other types of removal systems can be input to existing plants but no cost or performance model for them is available in CANSIM. The Electrostatic Precipitator (ESP) model used was developed based on discussions held with some ESP manufacturers. The model accounts for the effect of limestone injection on the ESP performance.

Carbon Dioxide Controls. The CO_2 emissions are computed based on the fuel carbon content, fuel heat value, and plant efficiency. Removal of CO_2 assumes a Selexol process that compresses flue gas to 1 379 kPa (200 psi) and separates the CO_2 and compresses it to 13 790 kPa (2 000 psi) for transport in the pipeline for disposal at sea or below ground. It is assumed that the total capital cost of this process is approximately $22,000 per ton of CO_2 removed per day. Pipeline costs are a function of the pipe diameter. The pipe diameter is computed based on the total number of stations using the pipe for CO_2 removal with a dense phase velocity of 1.0 m/s (3 ft/s). The pipeline costs are taken as $20,000/mile-inch diameter. The power costs for compression and to compensate for friction losses are computed and then the station output is adjusted to account for this.

Input Data Requirements

The following is a summary of the input data requirements for CANSIM.

a) Energy Demand

- Base year energy demand
- Projected demand growth rates
- Transmission line power loss
- Peak to average power demand (annual)
- Load/duration curve
- Unit capacity factor (energy generated/max. possible)
- Reserve power capacity margin desired above peak power demand
- Type of generation: hydraulic, nuclear, fossil, by unit
- Size of generating unit(s)
- Boiler design type(s)
- Turbine heat demand per kilowatt-hour of generation

b) Financial

- Capital investment for generating unit and pollution control equipment
- Interest rate
- Inflation rate
- Age of each unit
- Life expectancy of each unit
- Capital depreciation method
- Annual fixed operating costs of entire system

c) Fuel

- Heat content

Total sulphur content and pyritic fraction
Carbon content
Ash content
Fuel price and its projected price changes

d) Emission Control

i) Sulphur Dioxide Reduction Method
Wet scrubbing, dry scrubbing, furnace injection of sorbent, alternative fuel, coal cleaning, load reduction, and combinations of these
Dumping cost of FGD sludge

ii) Nitrogen Oxide Reduction Method
Low NO_x burners, sorbent injection or catalytic reduction

iii) Particulate Reduction Method
Electrostatic precipitators, baghouses

iv) Carbon Dioxide Reduction & Disposal

Summary of Outputs

- Projected required annual generating capacity for any specified future year, in megawatts (MW)
- Projected annual reserve capacity, MW
- Projected annual energy supply by system, and by generating type, MW hours
- Projected fuel demand for coal, oil or gas
- Distribution of fuel supply tonnage by sulphur content
- Generation distribution by fuel type
- Projected annual capital expenditure for new-generation capacity in base year and specified future year dollars
- Annual capital outlay for pollution control in current or future year dollars
- Projected annual operating costs and projected annual fuel costs, in current or future year dollars
- Projected system electricity costs in ¢/kWh, in current and future year dollars
- Projected annual emissions of SO_2, NO_x, CO_2 and particulate
- Specific emissions of each pollutant, in lbs per million Btu fired
- Annual capacity factor of each generating unit contributing to total energy output of complete system
- Annual operating costs, including annual capital repayment, for SO_2, NO_x, and particulate control system selected for consideration
- Costs per tonne of SO_2, NO_x, and particulate removed
- Incremental change in electric power price due to controls
- Overall costs of emission controls are valid only if the reserve margin for the no-control and control case is maintained equal. This accounts for the reduction in efficiency and capacity of the controlled plants.

Computers

CANSIM originated on a VAX computer, but it is now also running on a PC under MS/DOS. The running time is small, but the output is considerable. To make this easier to manage, most of the significant variables can be plotted as a function of time.

Appendix B

Terms of Reference

1. Title:
Technical and Economic Feasibility of Technologies for Flue Gas Control of CO_2 Emissions from Canadian Fossil Fuel Fired Electric Power Plants.

2. Background:
Global warming, the so-called greenhouse effect, has emerged as a real and growing global environmental threat that is viewed with growing concern by both Canadians and Canadian governments. This concern was highlighted at the World Conference on the Changing Atmosphere, hosted by Canada in 1988. One of the conference's recommendations was to reduce CO_2 emissions by approximately 20% of 1988 levels by the year 2005, as an initial global goal.

The federal and provincial governments have jointly responded to this challenge and bodies such as the Canadian Council of Ministers of the Environment (CCME) and the Energy Ministers' Task Force on the Environment are conducting reviews of the problem and are assessing possible implications for the Canadian economy.

This preliminary work and that of others clearly identifies fossil-fuel-fired electricity generation as a target for possible measures to reduce CO_2 emissions. In Canada, fossil-fuel-fired generating stations account for approximately 30% of installed generating capacity (about 30 000 MW), most of which is coal-fired. This source produces about 20% of Canada's electricity. Several provinces are now almost entirely dependent on fossil-fuel-based electricity generation. As demand for electricity grows, it is expected that other provinces will increasingly depend on fossil fuel generation.

While proven technologies exist that can economically reduce combustion-produced emissions of SO_2 and NO_x, such is not the case with CO_2. While limited work has been done in this area, notably in the U.S., no comprehensive assessment has been conducted for the Canadian situation. There is clearly a need to conduct an up-to-date review of potential CO_2 scrubber technologies or processes, and assess their technical and economic feasibility for Canadian fossil-fuel-fired generating stations. This project is the first step in this assessment.

3. Statement of Work:
A - Conduct a survey of possible CO_2 removal technologies.

1. Conduct a comprehensive survey of existing and emerging processes and technologies that could be applied to the removal of CO_2 from fossil-fuel-fired utility boiler flue gases.

2. Prepare a report outlining the current development status of each process. This should include, but not be limited to, the comparative estimated capital and operating costs, technical characteristics and problems, energy consumption, efficiency of scrubbing action, chemical reagents used and wastestreams produced, compatibility with generating plant configurations and operations, and reliability. The report should contain

appropriate recommendations for further study of one or more of the technologies.

B - Identify and evaluate methods for disposal of CO_2 removed from combustion flue gases.

1. Conduct a survey of alternative methods for disposing of CO_2, identifying the most promising in terms of effectiveness and cost.

2. Identify and assess the environmental problems that may be associated with the ultimate disposal of CO_2 removed from combustion flue gases.

3. Prepare a report on this phase of the work.

C - Conduct an evaluation of a potential CO_2 scrubbing system.

1. Select Canadian electricity generation scenarios for each province for the period 1988 to 2005 consistent with the most recent series of Environment Canada projections, and formulate a hypothetical CO_2 control program based on applying the selected scrubbing system.

2. Using the generation scenarios as a working reference, conduct assessments of the technical and environmental implication of implementing hypothetical emissions control programs.

3. Evaluate the impact of a CO_2 control program on the cost of producing electricity in each province and in Canada.

4. Prepare a report that presents the results of this work.

D - Present Results and Recommendations

1. Prepare a summary for the three phases of the project (A to C), identifying areas where future research, development and demonstration are required.

2. Present study findings at designated meetings.